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Mixing Resources

Electric Energy T&D MAGAZINE

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POWERPOINTS

Makes You Think

Working in the electricity transmission and distribution industry makes me what I consider one of the luckiest people that I know. My son-in-law is a lineman for a large utility in one of Canada's Maritime Provinces and my son is an electrician working in residential, commercial, and industrial sectors in and around Toronto. On rare occasions each of them grumbles about the job and I'm quick to remind them are working in one of the best industries on this planet.

With this in mind and as global populations struggle to get out from under the spectre of burning fossil fuels to create energy, there is no shortage of naysayers, doomsday prophets, fear mongers, NIMBYists, and others hard at work trying to debunk the fact that climate change and global warming are here. I don't profess to have all of the answers concerning these phenomena but I'm certainly not in a vacuum, nor am I incapable of reading the results scientists and other experts are grinding out and understanding the ramifications of 'what if?'

I recently came across a Facebook presentation that I found at once funny, shameful, frightening, and close to the truth. The piece airs with three serious looking people presenting themselves as executives working for the Australian Coal Mining Company extolling their 2014 Climate Policy Update. Each makes several comments to a seeming off-camera interviewer about how their firm is dealing with the effects of their daily activities, which include, amongst others, pumping tonnes of damaging carbon dioxide into the atmosphere.

Shot as head and shoulders against a plain background and sporting the most serious of demeanours the two men and one woman officiously explain, in no uncertain terms, how their company deals simply and effectively with two sides of a rancorous argument.

> **Tim Buckley**: As a company, we have an absolute commitment to the principle of action on climate change. We're very proud of our values.
> **Birgit Eichman**: But as one of the major contributors to CO_2 emissions, and as we begin to contend with the real-world effects of climate change, we have to prepare ourselves for the next step in addressing our corporate responsibilities in this area.
> **Rob Dean**: While the steps on the surface seem to be in opposition to our self-interest, the reality is, however, that they are actually in opposition to our self-interest.
> **Birgit Eichman**: So we've recognized what we call 'the gap.'
> **Rob Dean**: 'The gap' is the problem of simultaneously holding two contradictory positions.
> **Tim Buckley**: On one hand, to act on our responsibility to humanity, but on the other hand, to deliver on our commitment to superior value for our shareholders.
> **Rob Dean**: We needed to take a leap of faith.
> **Birgit Eichman**: An intuitive step outside of the limitations of science-based argument.
> **Tim Buckley**: I am proud to announce the company's new policy of 'f**k you.' 'F**k you' is more than a policy. It's a philosophy where we are able to straddle the dichotomy between what we know is true and how we can benefit by ignoring that truth.
> **Rob Dean**: 'F**k you' means we can be passionate about our values, but not act on them.

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2014 CIGRÉ CANADA CONFERENCE
"Innovation and the Evolving Grid"

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International Center – Toronto, ON

→ September 22-24, 2014

Hosted by: hydro one

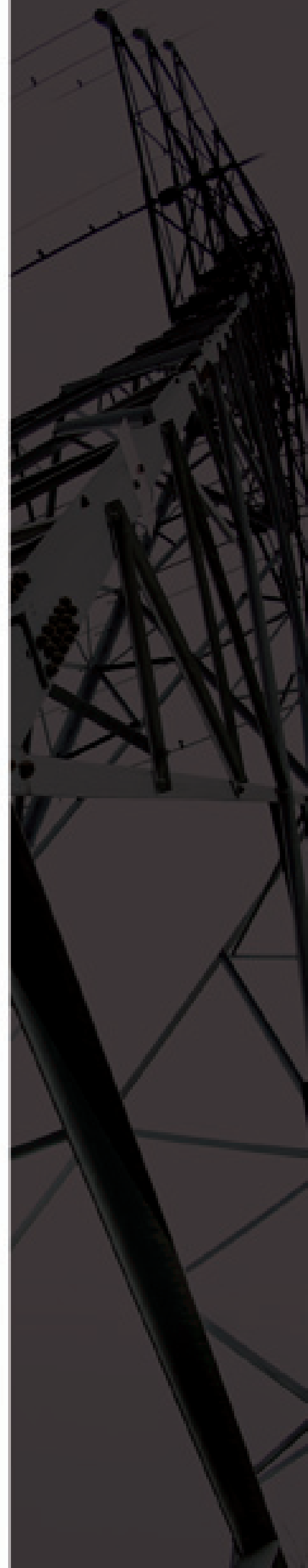
At the 9th annual CIGRE Canada Conference on Power Systems, the theme is *Innovation and The Evolving Grid.*

Electric utilities with transmission and distribution systems face tough challenges: planning, connecting and operating systems with radically different generation, including large solar and wind generation, and more power electronics-controlled loads.

Concurrently, utilities must ensure reliability and adequate power quality, reduce carbon emissions, minimize visibility of new builds, improve customer service, moderate electricity rates, manage aging infrastructure, and address climate changes and extreme weather concerns.

At this conference, deepen your understanding of these utility issues, the solutions, approaches, methods, and tools which have worked successfully, and seek answers to specific emerging issues at your utility.

Join us in Toronto, Canada from September 22 – 24, 2014, as business leaders, system planners and operators, asset managers, engineers, manufacturers, scientists, policy makers, regulators, academics and students come together to exchange information, network, and discuss these critical issues and the future of the power system.



Birgit Eichman: ‘F**k you’ takes what would be our present-day financial burden away from us and transforms it into a chronic, economic, social, cultural, and political crisis for future generations.
Tim Buckley: The genius of this, however, is that we transferred it away from us.
Birgit Eichman: It ensures solid returns to our shareholders by killing their grandchildren.
Rob Dean: With this policy, we delay action and leverage the gap, and are able to maintain our role as a global leader in destroying the planet.
Tim Buckley: Ultimately, this is a reflection of the values of our shareholders. Every day Australians have chosen to invest $20 billion into the company, but we prefer to think of it as 20 billion ‘f**k yous’ to the Australians of tomorrow.
Rob Dean: There will come a day when my moral choices will no longer be beholden to the shareholders, and a wave of profound regret and a sorrow will engulf me as I realize with painful clarity the enormity of the damage I have perpetrated upon humanity. And even if I plea with whoever has succeeded my role in the company to stop putting CO^2 in the air for the sake of my daughter’s grandchildren, he or she can turn to me and simply respond with ‘f**k you.’ And that legacy really does make me very proud.[1]

Yes, as you can imagine, this corporate ad is fake. It is three and one half minutes of the best, most poignant jabs at how many of the planet’s inhabitants are treating the giver of life that I’ve seen in a long while.

In an exactly the same, only different vein, I live in a region that is overrun with the NIMBY and BANANA crowd. They are fighting tooth-and-nail to prevent wind turbines from being built offshore in Lake Ontario claiming their view of the lake will be forever marred by these malicious monstrosities. I know their area well and I am at a dead loss as to how 60 metre towers, sitting two to three kilometres offshore, 500 metres apart would be the ruination of anyone’s view.

We are also fortunate in having an international airport, albeit small, sitting on our harbour front. It’s a gateway to one of the busiest and hottest metropolitan markets in North America. Billy Bishop Toronto City Airport (BBTCA) easily and conveniently services the Greater Toronto Area (GTA). The three resident major airlines, each operating fleets of quiet Short Take-off and Landing (STOL) aircraft, serve much of the continent and generate billions of dollars for city coffers. As I write this, the main airport tenant, a very successful airline, is petitioning the city to extend the existing runway by 400 metres to accommodate new-gen commuter ‘whisper’ jets. Use of jets is currently forbidden at the aerodrome as earlier versions do not meet Toronto’s noise bylaw. The new ones do, with room to spare.

Again, the NIMBY crowd in the immediate area are on guard claiming the excess noise will totally ruin their way of life. I find it odd that the airport was an integral part of Toronto’s hub long before any housing was ever built in the area. Yet the arguments continue as if the knowledge of the airport was somehow foist unseen upon the grousers. I should let you know that in light of the potential increase in commerce, our infamous Mayor is fully in favour of seeing the BBTCA expansion go through.

Let’s look at noise in relative terms as an offense to the senses. One summer evening I was enjoying the peace and quiet of the lake whilst sitting on the beach reading my book. About 500 metres offshore a rather clapped out cabin cruiser about 10 metres in length was heading due west, parallel to the shore where I was. This was probably the loudest engine noise I have ever heard belting out of a vessel afloat. I know of what I speak as an owner of a fairly large twin-engine FB cruiser. This deafening drone was an affront to me, creeping along at a few knots, totally destroying my enjoyment. The beach in Toronto extends over four kilometres west from where I was and I heard that flaming contraption well beyond that point. I wonder how many NIMBYites lodged complaints with Toronto City Council about their evening being so noisily disrupted or their view of the lake ruined by this old boat. For your information, during that 40 minutes or so, at least six STOL airliners landed or took-off at BBTCA, that sits just beyond where I could still hear the bucket of noise. If one didn’t look up, one would have missed the quiet airliners as they went about the business of serving our fair city.

If global warming and the threat of calamitous results from climate change weren’t so real, would there be a need for well-done parodies to surface. Have we arrived at that point whereby the solution discovered by the Australian Coal Mining Company draws a crowd? Is there a chance the naysayers might win? I don’t want to think so but unless we learn to manage this demon I fear I should be preparing for the worst.

[1] The piece is on the Upworthy site presented by Adam Mordecai. I really must thank him for posting it.

INDUSTRY NEWS

Ventyx Joins Swedish Utility to Create One of the World's Smartest Electricity Networks

Smart Grid Gotland to allow customers to control consumption based on energy prices and help utility meet European Union carbon emission reduction targets

Ventyx, an ABB company, announced it is joining an innovative initiative to create one of the world's smartest electricity networks, part of a development project entitled Smart Grid Gotland. As part of the project, Ventyx will deploy a comprehensive Distribution System Optimization solution encompassing network control, demand response management, demand forecasting and business analytics to support the project, enabling large quantities of wind and other renewable and distributed energy sources to be integrated into the grid, while maintaining reliability and providing better operational performance.

Ventyx is working with several partners on the project, including Gotlands Energi AB (GEAB), the utility serving the Swedish island of Gotland. GEAB is 75 percent owned by Vattenfall, one of Europe's largest generators of electricity, which is also a major partner in Smart Grid Gotland.

The project was initiated in response to the European Union's climate change target to reduce carbon emissions by 20 percent by 2020. Sweden plans to increase its renewable electricity production primarily through wind power, as generated on the Island of Gotland - the largest island in the Baltic Sea 90 km from the Swedish mainland - providing customers with low carbon, sustainable power supplies. After this Gotland pilot, the solutions and ideas could be transferred to larger-scale projects on the Swedish mainland and in other European countries, providing citizens with more reliable power and an opportunity to control their energy consumption and costs.

The distribution management system (DMS) software by Ventyx, integrated with ABB hardware, will be used to address bottlenecks in the distribution network that may restrict the flow from the wind turbines to consumers.

"Wind power is produced out in the distribution grid and, like solar energy, is highly variable, presenting challenges when it comes to power quality, surveillance and control of the grid," said Veijo Huusko, Head of R&D Portfolio Management, Vattenfall Nordic. "Using industry-leading network management software from Ventyx to create a more intelligent and efficient grid, we can increase the use of renewable energy sources, improve power quality and create added cost-savings for customers over conventional grid technology."

Ventyx Network Manager SCADA systems will cover one of the island's substation and its associated network - managing daily operations and helping to reduce the duration and frequency of outages through the use of smart meters and other equipment in the field. The Ventyx business analytics solution will analyze data from the SCADA/DMS/OMS system, and potentially other sources to help boost operational efficiency and reliability while reducing costs.

"The Gotland Smart Grid project is one of the world's most innovative and significant smart grid initiatives in demonstrating how modernizing electricity networks can support a greater variety of renewable energy sources while at the same time improving power reliability and customer control," said Jens Birgersson, head of the Network Management business at ABB, which acquired Ventyx in 2010. "It is a significant step forward in the development of a modern, sustainable society with the potential for it to serve as an international model for intelligent electricity networks."

Smart Grid Gotland is a cooperation project between Vattenfall, ABB, GEAB, Svenska Kraftnät, Schneider Electric and KTH, and is partly financed by the Swedish Energy Agency. The project was begun in September 2012 and will run to December 2015 and has three overall objectives:

1. cost efficiently increase the hosting capacity for wind power in an existing distribution system;
2. show that novel technology can improve the power quality in a rural grid with large quantities of installed wind power; and
3. create possibilities for demand-side participation in the electricity market, in order to shift load from peak load hours to peak production hours.

DiversityInc Ranks Ameren Among Top 3 Utilities in the Nation

For the fourth year in a row, Ameren Corporation was selected by DiversityInc as a Top 7 Regional Utility for Diversity for 2014. Ameren ranks third on the utility list this year, recognized for creating an inclusive workplace, reaching diverse customers and having strong supplier diversity.

"Ameren believes that diversity in our workforce, our selection of suppliers and strong support for the communities we serve are critical to achieving the level of performance our customers deserve and the economic support our region needs," said Sharon Harvey Davis, Ameren's Chief Diversity Officer.

Ameren also ranked ninth on DiversityInc's list of Diversity Councils. The specialty list is new this year, and is based on effective best practices for councils that promote employee skills, knowledge and experience, and supplier-diversity progress.

The rankings from DiversityInc are the latest honor for Ameren. The company has also been ranked among the top 25 diversity councils in the nation by the Association of Diversity Councils, a top 100 military-friendly employer by G.I. Jobs Magazine and a top 50 employer by Woman Engineer Magazine.

"Earning a spot on one of DiversityInc's specialty lists for workplace diversity proves that management is paying close attention to the needs of their primary constituents - employees, customers and other key stakeholders," said Luke Visconti, CEO of DiversityInc. "Companies with great reputations attract the best and most skilled employees who then create and deliver the best products and services."

TXU Energy Program Helps Cuts Business Electricity Spending by $51 Million

Through its 5-year-old Brighten GreenBack program, TXU Energy has invested $9.4 million in business customers' efficiency projects

TXU Energy has invested $9.4 million in efficiency projects for business customers which, combined with additional investments by those customers, has helped them cut their electricity consumption by 682 million kilowatt-hours since 2009. Based on a conservative price estimate, that's freed $51 million for those businesses to invest in their products, services, employees and communities.

'The Brighten GreenBack program allows our business customers to benefit from projects they might not have been able to fund otherwise,' said Scott Harrison, director of engineering and innovation for TXU Energy. 'It helps cover the initial investment in energy-saving projects, which then deliver lower energy costs for years and often decades.'

TXU Energy launched its Brighten® GreenBack program in 2009, offering rebates to large, commercial and industrial customers for energy efficiency projects. The company also provides expert guidance to select and complete the most valuable initiatives.

'Because a dollar spent by a business creates up to $5 in additional economic activity, TXU's Brighten GreenBack program is delivering tremendous value,' said Bernard Weinstein, associate director of the Maguire Energy Institute in SMU's Cox School of Business. 'At the same time, taking demand off the state's power grid helps ensure reliability for everyone.'

Schools, churches, government entities and well-known commercial businesses, including American Airlines and Marriott, have completed a total of 265 projects.

'By far, the most common projects have focused on lighting, often installing smaller, higher-efficiency systems to deliver equal or greater light,' Harrison said. 'On average, a lighting project will deliver 10 years of savings, so it often offers an attractive return on investment.'

In addition to lighting, many customers have focused on heating, ventilation and cooling system upgrades, as well as equipment and lighting controls.

'We don't just bring our dollars to the table,' Harrison said. 'We help find additional rebate opportunities from Transmission and Distribution Utilities and other sources, and we bring a deep pool of energy experts to ensure that our business customers get valuable returns.'

Consumers Energy, Michigan Governor Rick Snyder Kick Off Initiative to Promote Growth in Company's Hometown

Consumers Energy and Michigan Gov. Rick Snyder kicked off an effort to invigorate the Jackson-based company's downtown area, joining more than 18 businesses and three colleges to celebrate the start of the new Anchor Initiative.

"Caring for the communities we serve is our Promise to Michigan, and that is especially true in our hometown," said Consumers Energy President and CEO John Russell. "Businesses like ours can enable Michigan's downtowns to thrive, and we think what we are doing in Jackson can be a model across the state."

Russell spoke about the company's plan to convert downtown Jackson's former Woolworth Building into a hub for business innovation. Consumers Energy's strategic innovation and utility business development teams will work in the building, along with The Heat and Warmth Fund (THAW) and CP Federal Credit Union.

Consumers Energy will encourage employees to live downtown, within a short walk of the company's corporate headquarters, and collaborate with other Anchor Initiative members on ways to build a vibrant center in which to live and work.

"We started more than 125 years ago in Jackson and have served this community and Michigan for that entire time," said Patti Poppe, Consumers Energy's vice president of customer experience, rates and regulation. "Our ability to attract top talent depends on a healthy Jackson, with a vibrant downtown that's an attractive place to live, work and innovate."

The kickoff event for the Anchor Initiative took part in Jackson's Bucky Harris Park, which was built on the original town square for the city, located 80 miles west of Detroit. Also speaking during the kickoff were leaders of Michigan International Speedway and Commonwealth Associates, a Jackson-based company that is committed to expand in the city.

Besides its support for the Anchor Initiative, Consumers Energy already focuses its spending on Michigan. The company is on target to reaching its goal of increasing spending with Michigan-based suppliers by $1 billion over five years. Consumers Energy was one of the first companies to join the state's Pure Michigan Business Connect, an effort promoted by Gov. Snyder and the Michigan Economic Development Corp. that encourages Michigan companies to invest in the state.

Fraser Institute: Policies that raise energy costs limit economic growth in Canada

Limiting the availability and raising the cost of energy can hurt Canada's overall economy and weaken future growth, finds a new study released by the Fraser Institute, an independent, non-partisan Canadian public policy think-tank.

The study, Energy Abundance and Economic Growth, examines the long-term relationship between economic growth, energy availability and energy consumption with evidence from Canada and around the world.

'Energy use and economic output grow together over time, and the evidence shows that if you limit energy use you damage future economic growth prospects,' said Ross McKitrick, study co-author, Fraser Institute senior fellow, and economics professor at the University of Guelph.

Since 1980, notes the study, Canada's energy use grew by about 50 per cent while Canada's Gross Domestic Product (GDP) doubled. During that same period, global energy use almost doubled while global economic output increased six-fold. Evidence from around the world indicates that energy use triggers growth and is not simply a by-product of growth.

So what does this mean for policy-makers?

Because the best available evidence suggests that promoting energy abundance helps sustain strong economic growth, policies that deliberately increase energy costs will likely have negative economic consequences now and in the future.

'It's obvious'energy drives economic growth. Yet policy-makers across Canada continue to treat energy consumption as a bad thing, and act as though cutting energy use is an end in itself. They need to understand the long-term costs of this thinking,' McKitrick said.

For example, policies that increase energy costs or limit its availability (i.e. renewable energy mandates or the required use of biofuels such as ethanol or biodiesel) diminish competitiveness, reduce rates of return on investment, and reduce economic growth. Moreover, conservation mandates and strict appliance standards (i.e. water heaters, refrigerators) often have no conceivable environmental benefit but are justified simply because they cut energy use.

'The Ontario government, for instance, claims that the Green Energy Act, which increases energy costs, thereby making it less abundant, is part of the province's economic growth strategy. The evidence points in the opposite direction'the Act will limit future economic growth,' McKitrick said.

President Obama to Make Energy Efficiency a Key Strategy to Tackle Climate Change

On May 9th, President Obama is expected to announce important new commitments and executive actions that represent major steps forward for energy efficiency. The White House projects that these energy saving actions will result in more than $26 billion in savings by government, consumers and businesses, while also creating new jobs and reducing carbon pollution by 380 million metric tons.

The most important efficiency elements that the president will announce are two major new energy-saving appliance and equipment efficiency standards. These standards, years in the development, cover large electric motors that are commonly used in industry and commercial buildings and walk-in coolers and freezers used to store perishable items like milk and eggs at grocery stores. After comparing the savings estimates provided by the White House to levels achieved by the proposed rules issued in late 2013, Appliance Standards Awareness Project (ASAP) executive director Andrew deLaski made the following statement:

"The Obama administration has hit home runs with these two new energy-saving standards. By spurring improved efficiency in electric motors and supermarket refrigeration systems, they will reduce energy waste, save money and cut pollution. The more than $26 billion in electric bill savings achieved by 2030 from the new standards will make U.S. businesses and industry more competitive, strengthening the U.S. economy and creating jobs. Today's announcement is also good news for the environment. The administration is now more than two-thirds of the way to the president's goal of three billion metric tons of CO2 reductions by 2030 from new standards completed during his presidency."

The president's announcement will include other important provisions that ACEEE has been supporting, including: expanded investment in energy efficiency for Federal buildings; support for adoption of the most current commercial building codes; financing for energy efficiency in affordable and multifamily housing; and commitments from state and local governments, businesses and financing institutions for investments in energy efficiency.

In response Neal Elliot, associate director of research for the American Council for an Energy-Efficient Economy (ACEEE) made the following statement:

"The climate report released earlier this week showed the damage that will occur if we don't act now to reduce emissions. The energy efficiency commitments made by the president today will not only benefit the environment by lowering carbon pollution, they are good news for our pocketbooks too. Energy efficiency can save money in every nook and cranny of our economy-these actions will reduce energy waste in industrial plants, commercial buildings, low-income housing, restaurants and supermarkets, water treatment plants, federal buildings, and more."

EPA Recognizes PHI Utilities as 2014 ENERGY STAR Partners of the Year in Energy Efficiency Program Delivery

Pepco and Delmarva Power Earn Awards for Protecting the Environment Through Superior Residential Energy Efficiency Programs

The U.S. Environmental Protection Agency (EPA) has recognized Pepco and Delmarva Power as 2014 ENERGY STAR® Partner of the Year winners for outstanding contributions to reducing greenhouse gas emissions by delivering energy efficiency programs, information and services to its customers. The accomplishments of the two Pepco Holdings, Inc. (PHI) companies were recognized on April 29 at the Marriott Wardman Park Hotel in Washington, D.C.

Pepco and Delmarva Power were honored for their residential energy efficiency programs offered to Maryland customers and their work to increase market share of energy-efficient ENERGY STAR certified products, services, and programs as leaders in energy efficiency program delivery through comprehensive outreach, education, and marketing programs.

"PHI companies are dedicated to our partnership with ENERGY STAR," said Hallie Reese, vice president, customer care, PHI. "Through our suite of residential energy efficiency programs — Lighting Program, Appliance Rebate, Appliance Recycling, HVAC Efficiency, Quick Home Energy Check-up and Home Performance with ENERGY STAR — we are helping our customers save money and energy, lower energy costs and learn more about energy efficiency, while simultaneously addressing climate change." In 2013, with help from ENERGY STAR, American families and businesses have saved $297 billion on utility bills and prevented more than 2.1 billion metric tons of greenhouse gas emissions.

"Pepco and Delmarva Power have set a high standard for organizations nationwide that deliver energy efficiency and environmental programs," said EPA Deputy Administrator Bob Perciasepe. Pepco's and Delmarva Power's residential programs include the lighting program that offers instant in-store discounts on select ENERGY STAR certified CFL bulbs, LED bulbs and lighting fixtures at participating retailers.

Also, rebates are offered through programs for purchasing ENERGY STAR certified appliances, upgrading to a high-efficiency cooling system (air conditioner or heat pump), getting a performance tune-up of existing HVAC equipment by a participating contractor, scheduling a no-cost quick home energy assessment that also provides simple energy-saving products, or a comprehensive home energy assessment, building ENERGY STAR certified new homes and recycling an old refrigerator or freezer.

Our programs support the EmPOWER Maryland goal of reducing statewide energy consumption 15 percent by the year 2015. For details on the residential programs, visit pepco.com/saveenergy or call 1-866-353-5798; delmarva.com/saveenergy or call 1-866-353-5799.

Fortis and UNS Energy File Settlement Agreement

Includes Customer Benefits Totalling US$30 Million and US$220 Million of New Equity

As previously reported on January 10, 2014, Fortis Inc. ("Fortis") (TSX:FTS) and UNS Energy Corporation ("UNS Energy") (NYSE:UNS) filed an application with the Arizona Corporation Commission ("ACC") requesting that the ACC approve a proposed merger ("Merger") in which UNS Energy would become an indirect wholly owned subsidiary of Fortis.

Completion of the Merger is subject to the following remaining processes: the approval of the ACC; the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended; the review of the Merger by the Committee on Foreign Investment in the United States; and the satisfaction of other customary closing conditions.

On May 16, 2014, UNS Energy, Fortis, ACC Staff, the Residential Utility Consumer Office and other parties to the Merger proceedings entered into a settlement ("Settlement") in which the parties agree that the Merger is in the public interest, and recommend approval by the ACC, subject to certain conditions. Those conditions include, but are not limited to, the following:

- UNS Energy shall provide benefits totaling US$30 million over five years to the retail customers of its utility subsidiaries Tucson Electric Power Company, UNS Electric, Inc. and UNS Gas, Inc. (collectively, the "Regulated Utilities"); US$10 million in year one, and US$5 million annually in years two through five. The amounts will be credited to customers' bills.
- UNS Energy and the Regulated Utilities will adopt certain ring-fencing and corporate governance provisions.
- Dividends paid from the Regulated Utilities to UNS Energy cannot exceed 60 percent of the Regulated Utilities' respective net income for a period of five years or until such time that their respective equity capitalization reaches 50 percent of total capital (excluding any goodwill recorded) as accounted for in accordance with U.S. Generally Accepted Accounting Principles. The dividend restrictions are contingent upon receiving necessary consents of the lenders in UNS Energy's credit facility.
- Fortis shall make an equity infusion totalling US$220 million through UNS Energy into the Regulated Utilities following closing of the Merger. However, if the Merger closes after September 30, 2014, the equity infusion may be made into UNS Energy to retire debt.
- The Settlement is subject to the review and approval of the ACC, which could approve, reject or require modifications to the Settlement as a condition of approval. ACC approval of the Merger must be obtained before the Merger can be completed.
- All of the Merger conditions are described in the Settlement, which can be accessed through a link at http://www.uns.com/acquisition/. All documents filed with the ACC related to the Merger can be accessed on the ACC's website at http://edocket.azcc.gov/. The docket numbers are E-04230A-140011 and E-01933A-14-0011. Information contained on these websites is not part of any report filed with the SEC by UNS Energy or Tucson Electric Power.

As previously reported on April 18, 2014, the ACC administrative law judge ("ALJ") assigned to this matter issued a procedural order adopting the following schedule:

- Testimony in support/opposition to settlement agreement - June 2, 2014
- Settlement agreement responsive testimony - June 13, 2014
- ALJ hearing commences - June 16, 2014

Fortis and UNS Energy expect the Merger to close by the end of 2014.

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid

Mixing Resources

**Rick Nicholson, Sr. Vice President
Transmission and Distribution
Solutions with Ventyx an ABB company**

We are in conversation with Rick Nicholson, Sr. VP T&D Solutions with Ventyx, an ABB company. He and his teams are spearheading the company's vision to create solutions that will meet the present and future needs of utilities at home and abroad as they use smart grid technologies to cope with the complexities introduced by renewable and distributed energy sources.

EET&D: Rick, you have been in the energy business for some time, why is the integration of renewable and distribution energy resources such a challenge for utilities?

Nicholson: There are a couple of fundamental challenges, actually. The first is economic as the growing adoption of distributed energy resources impacts the traditional utility business model. For example, GTM Research projects that U.S. distributed generation from solar PV will more than double over the next two and a half years. As that kind of exponential growth continues, grid revenues from the sale of kilowatt hours will naturally erode, leading to rate increases, in turn leading to even faster adoption of alternative energy sources, and so on. This is a scenario that is keeping a lot of utility execs awake at night. Regulators are also concerned about this, as evidenced by the New York Public Service Commission's recently released utility business model reform proposal.

The other big challenge is operational. The grid was designed for one-way power flows from large central plants to consumers. By injecting power at the edges of the grid, distributed energy resources change this picture significantly. Now, there is a two-way power flow. Also, with large coal or nuclear plants, you have predictable and controllable energy output. Renewable energy resources, on the other hand, only produce power when the wind blows or the sun shines. Add them to the mix, and you introduce intermittency to the energy supply.

All of this makes the grid more complex and harder to operate. Nevertheless, renewable energy sources are what customers want and what policy-makers and regulators are mandating.

EET&D: Where do you see the operational challenge playing out today, and in what markets do you foresee it being a problem in the future?

Nicholson: Increased grid complexity is going to be a problem in any region where there is high adoption of renewable and distributed energy resources, including the U.S. Right now we are seeing considerable activity in Northern Europe, a region that has been at the forefront of integrating renewable energy sources. What they've found is that increased grid complexity translates to increased stress on control center operators. This in turn leads to mistakes that can cause outages or overstressed equipment. Taking the bull by the horns, E.ON Sweden is developing a next-generation smart grid control center aimed at increasing automation and operator visibility across the grid and providing greater control over distributed generation.

Another interesting Swedish project is underway on the island of Gotland, which is home to much of the country's distributed generation facilities. Called Smart Grid Gotland, the project will let customers control consumption based on energy prices while helping the local utility, Gotland Energi AB, which is partially owned by Vattenfall, meet ambitious EU carbon reduction targets.

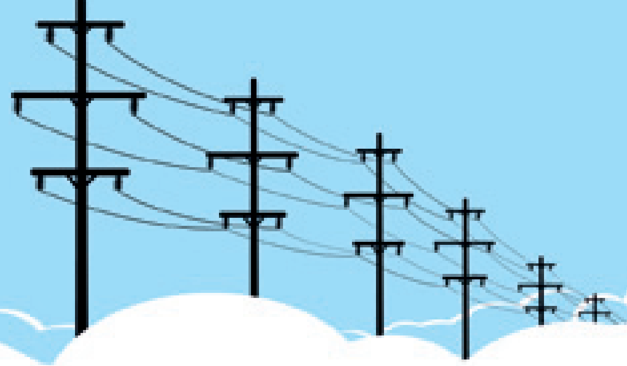
I believe that these and other current projects will provide valuable reference architectures that can be emulated in utilities the world over.

EET&D: Speaking of Europe, German utilities are struggling financially because of high penetration rates of solar. This has led to a number of investment banks warning investors that solar could put utilities out of business. Will the grid survive?

Nicholson: Like roads and rail lines, the grid will survive. It's how individual utilities will survive and prosper that is in question. One of the most important socioeconomic trends of our time is the new sharing economy, which has already completely refashioned key industries from music and entertainment to journalism and publishing.

THE GRID TRANSFORMATION FORUM

Envisioning the 21st Century Grid



With the rise of companies like Uber and Lyft, sharing is even hitting taxi and limo services. And, when sharing comes to an industry, companies that stay wedded to legacy business models inevitably fall by the wayside.

There is no way that utilities will be immune to the sharing economy. Already we're seeing 'solar gardens' that share the costs and benefits of installing solar, nascent networks of electric vehicle charging stations that are utility-independent, and internet-connected thermostats that slash power consumption. These and other innovations all have the potential to damage utility revenues and profits.

But utilities can innovate too and augment or transform their traditional business model, and many are working with regulators and policy makers to do so. Consider that most innovations around energy connect to the grid at some point, and who best understands the local grid and energy markets? Who has the expertise and inside track to energy consumers? Rather than staying wedded to selling kilowatt hours, utilities can leverage all of these advantages and resources to create new revenue streams based on value-added grid services, either by providing those service themselves or by partnering with third-party energy service providers. Those that seize this opportunity today will be tomorrow's players.

EET&D: Where do you see plug-in electric vehicles fitting in? The grid wasn't designed to handle them in large numbers. How is it going to cope with their rising popularity?

Nicholson: Plug-in electric vehicles are introducing new challenges for utilities, particularly around demand peaks at night, which the grid isn't prepared to handle gracefully. It's a bigger problem than you might think. A single 240-volt EV charger adds the grid-load equivalent of three homes with air conditioning, lights, and laundry appliances running simultaneously, according to IEEE.

And, the problem isn't going to go away. According to a recent report by IHS Automotive, global production of EVs is expected to grow 67 percent in 2014, to a total of more than 400,000 vehicles. This will bring the total number of EVs in use worldwide by the end of 2014 to 1.1 million.

The key to facing this growing challenge is employing technology to harmonize and optimize how EV owners use the grid with how the grid is designed and operated. This is being done in places like California, where utilities are working to synchronize EV charging demand with power from wind farms, which tend to deliver their energy output overnight. There, utilities and regulators are harnessing smart meters to choreograph EV home-charging stations to the grid's available power.

Many utilities in other regions around the world are working on solutions to this challenge as well. For instance, Ventyx and ABB are working with a major Swedish utility to develop EV/charging station/utility demand response systems that monitor local network conditions and adjust EV charging accordingly. By creating a smart, flexible automated EV infrastructure along the entire supply chain, from grid to plug, utilities can enable residential customers to let utilities throttle fast EV chargers as necessary, delivering maximum available power to EVs while maintaining local network integrity.

EET&D: You have your eye on a lot of different technologies. Tell me, what technologies should utilities be considering when addressing the distributed energy challenge?

Nicholson: Addressing the challenge effectively requires a combination of information technology, or IT, and operational technology, or OT. Operational technologies include the latest generation sensors, communications networks, intelligent switches, energy storage systems, and intelligent solar inverters that underpin the smart grid. Information technologies unlock the value of this smart equipment.

The overarching IT solution that utilities need to be focusing on is Distribution System Optimization, which encompasses technologies for advanced distribution network management, demand response management, business analytics and – this is particularly important – demand forecasting. Going back to the Smart Grid Gotland project I mentioned earlier, all of these IT components are being deployed to integrate large quantities of renewable energy sources into the grid, empower consumers to make smart usage choices, and meet environmental goals. The next-generation smart grid control center project at E.ON Sweden that I mentioned highlights how these IT components meld with OT components such as grid sensing to give operators real-time visibility and ensure network reliability and efficiency.

Interestingly, Distribution System Optimization is bringing to distribution environments certain advanced applications commonly used in transmission. I'm talking about applications such as state estimation and contingency analysis that are becoming just as important to distribution as grid complexity continues to soar.

EET&D: I know that you're incredibly busy Rick and I can't thank you enough for taking the time to enlighten and encourage us. It's certain that you have a complex job in front of you. I know our readers will find it refreshing to understand your take on real solutions and the associated technologies for utilities that Ventyx ABB will integrate in the transformation of the new mix of electricity generation.

GREEN OVATIONS

Innovations in Green Technologies

Well Past Time for Co-generation in Canada

By Dan Cloutier and John Hodson

Europe and Asia are well versed in the benefits of combined heat and power [CHP] or co-generation. This knowledge comes in companion with electrical costs of $0.25/ kWh and gasoline costs of $2.50 per litre along with multiples of two times or more for any comparable energy source in North America. The focus of this article is not renewable energy but it certainly has a significant green content and dependent on fuel it can be a very green solution. The generators will normally run on natural gas but options include propane, diesel, gasoline, oil and in some cases naturally occurring off gas/methane or bio-diesel. Some applications allow for multiple fuel options so that the generator can run on the most economic or available fuel at the time.

A commonly unknown fact and one that made it quite clear to me that distributed co-generation is only in its infancy in North America follows. The major use of energy on the planet earth is transportation, which includes all modes from trains, planes, ships, trucks, automobiles, and recreation vehicles. Not so hard to believe. The second expenditure of energy is wasted as heat in the generation of electrical power at large central power plants whether coal, nuclear or fossil fuels and in the losses related in transmission and distribution of the power to end users. This constitutes a full 27 percent of the annual global energy use or 30,000,0000,000,000,000 (quadrillion) BTU during 2014 in North America alone. Just for interest's sake industrial energy use is a close third at 23 percent.

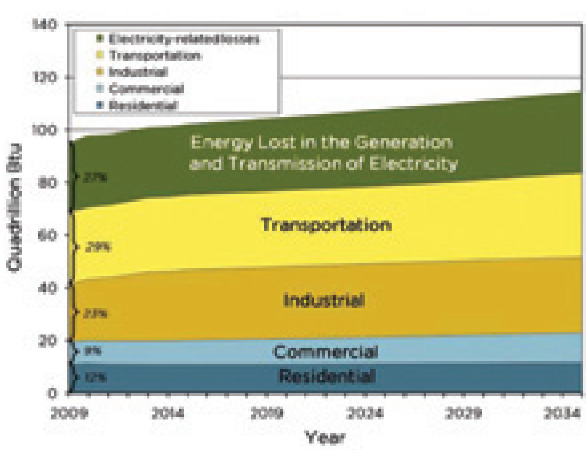
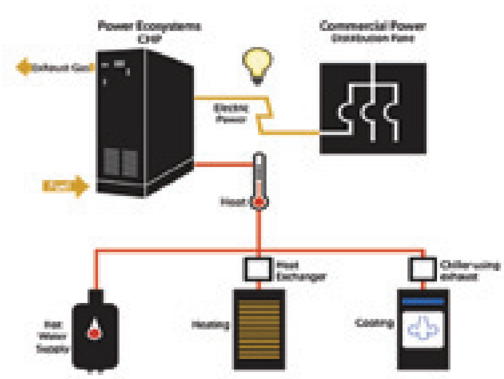


Figure 2. U.S. energy consumption by end-use sector projected through 2035. This is the EIA's reference case projection from its *Annual Energy Outlook 2011.*[12] Roughly 68% of the energy used to generate electricity is unavailable due to generation and transmission losses.

So generating electrical power out in the "boonies" and transporting that energy after first transforming the voltage to higher transmission levels and then down again to distribution and again to utilization levels has its serious efficiency drawbacks. In addition to this the simple resistive (I2R) losses over long distances can be significant. The heat generated is usually pumped into lakes, often causing some potential aquatic issues or up the stack again creating other potential environmental concerns. Bottom line is that the heat energy is wasted. We are seeing more and more local distributed energy by utilities such as Enmax's new downtown distributed energy center where hot water is used to heat nearby buildings. Reality is this is a drop in the bucket compared to overall electrical generation and consumption.

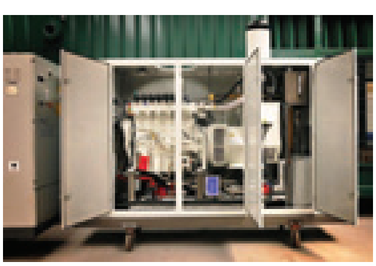
We need to get our heads out of the sand and start realizing the future is here now and planning infrastructure that makes sense for the next 20 to 25 years and beyond. Having a gas fired boiler sitting beside a conventional standby or peak shaving generator makes no sense. Sort of like running an electric heater in your car instead of gathering the engine heat. Amazing enough these projects typically pay for themselves in three to five years. In some specific cases the costs are recovered in less than two years. I cannot remember such a viable payback option since regulated electricity times when reduction of annual peak energy charges could be realized through power factor improvement or peak shaving technology.



In the de-regulated world we now find ourselves CHP would seem to be king. Not only does the owner get the benefit of reduced transmission and distribution costs but the essentially free heat energy can be used for other energy requirements such as domestic hot water, space heating or even chilling requirements through a heat exchange system. The CHP system is designed to be very efficient in recovering the maximum heat and includes the engine jacket as well as the exhaust to squeeze every bit of energy out of a highly efficient package.

Co-gen will work in any application where a base load of electrical power (kWh) exists and a relative sized thermal load exists (BTU). In some cases the thermal load is seasonal but in many cases an annual electrical and thermal load can be matched up for an extremely attractive application. In Europe and Asia there are thousands of installations running systems from our key manufacturing suppliers Ener.G and Yanmar including hotels, supermarkets, industrials, car washes and institutional facilities. A good example of a perfect match for co-gen is a hotel where the heat generated is used to keep the pool water, showers, laundry, space heating and the electricity for the guests power needs all simultaneously at the highest efficiency level available.

Sizing of generation is usually dependent on the facility base minimum electrical load. In some cases where thermal load is larger than the comparative generation output the additional power can be exported to the electrical utility. This requires some additional interconnect protection and control but this is normally possible without too much trouble in our new de-regulated energy environment. There are applications where the electrical and thermal energy can be shared among several related facilities using internal or utility conduits. An example as case in point is the new Enmax Boyle Renaissance Project in Edmonton. Even personal homes have gained the benefit of CHP technology. Co-gen can make sense from 5 kW to 100 MW size and beyond. The majority of corporately financed projects for medium size distributed power are in the 250 kW to 5 MW range.

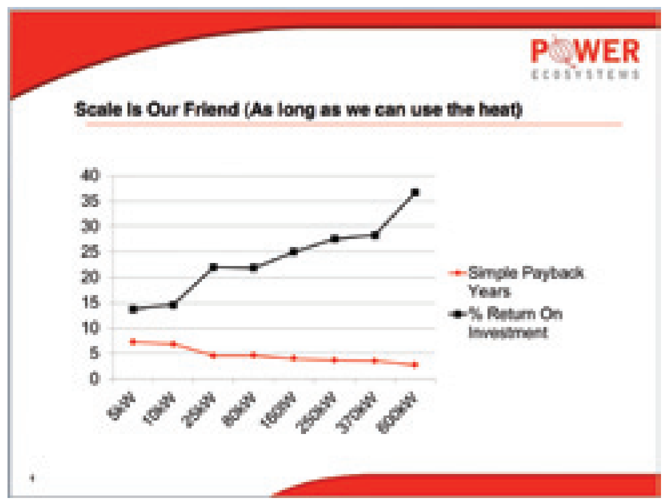


Engineering and installation is pre-engineered, productized and made as simple and straightforward as possible. The units are supplied in an indoor or outdoor sound proofed enclosure. All requirements for controlling and protecting the generator is self-contained. This includes advanced diagnostics and remote control and alarms. The connections are:

- fuel for the engine [typically natural gas]
- exhaust to atmosphere
- heat transfer medium [typically cold water]
- heat transfer out [typically hot water or steam]
- electricity out [typically 600V / 3 Phase / 4 Wire]
- electrical instrumentation signals [PT & CT]

Installation times dependent on size and location can be as little as a few days. Work is usually performed turnkey by the generator supplier but in certain cases the roles are split between customer selected engineering firm and contractors.

Financing can be provided by external financial institutions the generator supplier or even on a lease basis. Typically the dynamics of the project cost and payback drive the customer to self-finance based on 3 to 5 year payback time and sometimes less.



Installed cost, all in, for systems larger than 150 kW is generally about $1800 to $2600/ kW. This of course varies on size and location, the larger the generator the lower the cost per kW installed. Co-gen units are designed (budgeted) for continuous operation with regular maintenance practice to last 20 years. Longer duration is certainly possible but typically maintenance and repairs will start to be onerous dependent on actual in situ operation. Maintenance can be performed by the owner but usually is performed under contract and extended warranty by their representative.

To this point the benefits of co-gen have been promoted based on economics and of course saving money. This is a driving force and is usually justification on its own. The reality is that several other collateral benefits are realized which in some cases carry enough merit regardless of financial benefits. Some of these additional benefits include:

- Standby power in the event of normal supply failure. The co-gen can power important loads in the event of storm, flood, infrastructure upset or other catastrophic event
- Dual use as critical load/emergency generator to meet with building code compliance. The co-gen can serve as a power supply for base building loads and if emergency power is required the generator will serve this function until the requirement is past
- Extra stability to the facility power system when utility connection is weak or prone to voltage fluctuations, the generator can also be used to correct power factor for additional savings if penalties for low power factor are realized. The generator can also reduce peak energy penalties or "peak shave" again if benefit is realized
- The positive environmental impact is large and can result in several recognized benefits such as reduction in transmission and distribution infrastructure [steel, aluminum, concrete and copper] as well as reduction in unsightly overhead lines. Reduced I2R losses due to in-situ generation, no wasted energy. For the commercial sector co-gen can provide one of the best returns for dollar on prestigious LEEDS points

As stated at the beginning of this article the benefits of co-gen have long been realized in Europe and elsewhere in the world where energy costs have already reached a tipping point and beyond. Our tipping point is here and the future will only provide more reason to get on board with CHP. As with any newer ideas there will be leaders and followers but inevitably co-generation will become more and more a part of our infrastructure.

This is a value investment with many additional benefits. The time for co-gen is now.

White House Issues Executive Order in Support of CHP

This morning, on August 30, 2012, President Obama signed an Executive Order calling for action in the deployment of 40 gigawatts of new, cost-effective industrial Combined Heat and Power (CHP) capacity in the US by 2020. For more details, we urge you to read the Executive Order. *http://www.smartgridnews.com/artman/publish/End_Use_Efficiency/Is-CHP-really-one-of-the-next-big-things-5080.html/?fpt*

About the Authors

Dan Cloutier is president of Power Ecosystems Inc. and has significant expertise in incubating high-growth technology-based companies. Dan's first involvement with combined heat and power solutions was as a volunteer Board member of Cardel Place where Dan spearheaded pursuing the first Gold Leed designation in Alberta about a decade ago.

Power Ecosystems exclusively distributes Ener.G and Yanmar cogeneration systems in Canada. Collectively, with these partners, the company has over 6,000 commercial building cogeneration installations throughout the world. Power Ecosystems has been installing these systems in Canada since 2006, we are the Canadian under 1MW market share leader with installations completed for the likes of Atco, Enmax, Melcor, the cities of Calgary, Edmonton, and Saskatoon as well as Oxford Developments.

John Hodson is the founder of Magna IV Electrical Engineering Calgary and co-founder of Power System Asset Management Solutions and a shareholder of Power Ecosystems.

From Research to Action

Unleashing Innovation on the Electric Grid with Enabling Standards

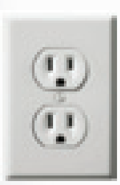
By Matt Wakefield, Director, EPRI and Ron Cunningham, IT Enterprise Architect, American Electric Power

Introduction

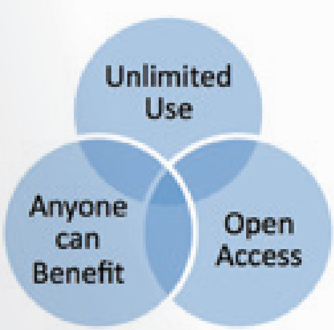
The electric grid has a long history and foundation of standards that began with the formation of the American Institute of Electrical Engineers (AIEE) in 1884. Within a year of its founding several technical committees were formed including one tasked with establishing standard names for electrical and other units.

Common names and terminology were part of the foundation of grid standards – this enabled the development and commercialization of products that produced and consumed electricity by allowing them to interoperate on the grid at the defined frequency, voltage, and power boundaries. The same holds true today – common and standard terminology is an important attribute to unleash innovation on the grid. Over the last couple of decades, information technology (IT) is increasingly being used on the grid. Electric utilities are able to extend their communication infrastructures to reach more connected devices, sensors, meters, resources, and other stakeholders beyond their own enterprise. Standard languages are just as important today as they were in the beginning to enable development of connected devices that can produce or consume electricity more intelligently to help balance electricity supply and demand.

Three Attributes of Standards to Enable Innovation:



What attributes of standards enable innovation? An early example is the electric plug and socket standard. Its attributes enabled innovation and allowed rapid development of derivative products and fostered radical changes in performance from those derivative products. This 'interface' of sorts was designed without knowledge of the future devices which would eventually utilize this plug/socket design and become standard in every home and building with similar standards around the world.



Attribute #1: Unlimited use
The standard electrical plug/outlet was designed without knowing what would be plugged into it nor what the source of electricity would be. Beyond the basic physical and electrical boundaries, any new product needing power can be developed to get power from this plug.

Attribute #2: Open and unrestricted access (to utilize the standard)
The National Electric Manufacturer's Association (NEMA) 5-15R is the standard outlet used in the United States – the standard is accessible and, within the bounds of the standard, anyone can use it.

Attribute #3: Anyone can benefit
The standard itself has minimal boundaries and does not prohibit the production of new and innovative products because the standard doesn't specify how it should be used (within the boundaries of physical and electrical parameters).

The standard plug/outlet, in its simplicity, enabled the development and commercialized products that could benefit from consuming electricity.

EPRI, along with utility membership and stakeholder engagement have contributed to standards efforts for the utility industry for decades in many disciplines, e.g. actual operation methods and techniques, electrical, mechanical, chemical, metallurgical, IT and telecommunications. Some of the earliest IT standards were in the original Utility Communications Architecture (UCA) with one of the emerging standards being the Inter-Control Center Communications Protocol (ICCP) or IEC 60870-6. ICCP is used almost exclusively for messaging between control centers worldwide and became critical to support the operation of interconnected grids and electricity markets.

Utilities use a combination of standards, be those defacto standards or national/internationally developed and approved e.g. DNP3, IEC 61850, CIM, Multispeak, IP, and the list goes on and on. Why do we use standards? To have flexibility to pick and choose products and tools that address the ever changing business needs with the most affordable cost to achieve and sustain the required business solutions.

More times than not, the business requirements and needs drive utilities to look for interoperability across multiple solution providers to enable interchangeability of a solution, product or tool which helps reduce the costs to achieve sustainability across the business needs. This is important because the lifetime of individual solutions can vary and new solutions will be added or replaced that must co-exist with legacy systems. Having solution providers that utilize standard protocols simplifies interchangeability from one solution to the next.

Standards conformance testing is also critical to make sure solutions deployed will indeed do what is claimed. One may assume that if a solution is utilizing a standard, it will interoperate with another solution using the same standard, but unfortunately, it's not that simple. Standards may have different versions or a variety of options or use profiles that are valid, but if different from one system to the next, they will not interoperate among different systems. Conformance testing and certification is a process that validates solutions utilizing a particular standard will interoperate with another certified solution using the same standard.

Security is another critical component of standards that must be architected, designed or built into the products and tools. The appropriate level and use of cyber security should not be considered as an afterthought add-on, though many times it could be necessary when transitioning from what is currently deployed to what a more desirable solution design might be to preserve legacy systems during the transition.

Application of IT Standards for an Integrated Grid

As we look back at some examples of history and attributes of standards that enable innovation, we can compare them to changes happening today in the electric power system. One example is the rise of distributed energy resources (DER), such as solar photovoltaics (PV) connected to the distribution system. In many settings, these distributed resources already affect the grid and their projected expansion may significantly change the technical, operational, environmental, and financial character of the electricity sector. EPRI refers to this as the 'Integrated Grid' and has begun work on an initiative that has several facets including the application of standards. As IT is increasingly being utilized and combined with electric grid to enhance operations, the development of the IT-related standards such as OpenADR 2.0b can play an important role in connecting and managing DER on the distribution system.

The convergence of IT and operational technology (OT) offers the promise of improving automation in a variety of areas. Today, most DER deployed is not managed, whether it is a PV system or a load, and standards can be a key enabler to foster innovation and automation of DER to support the grid just as the ICCP protocol enabled interoperability on a regional basis.

Does OpenADR offer attributes of a standard that may foster innovation and automation? Here is a quick analysis of OpenADR and attributes that may enable innovation:

Attribute #1: Unlimited use.

The OpenADR standard is primarily focused on the physical attributes of resources – it doesn't need to know what type of resource it is, but rather its electrical characteristics (load dispatch set point, load control capacity, charge state, etc.) Whether the resource is a generator, load, microgrid, building, vehicle, battery or something we haven't thought of, it is applicable.

Attribute #2: Open and unrestricted access.

The standard is based on the OASIS Energy Interop and is available on the OpenADR web-site – free to the public. Open access to the standards enables others to develop products that interoperate, are interchangeable and support required cyber security requirements.

Attribute #3: Anyone can benefit.

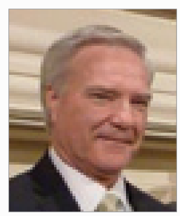
Because it is a public standard, anyone can produce products that meet the specification and go through the OpenADR Alliance certification process. EPRI has even developed OpenADR 2.0b open source software to evaluate the standard in our demonstrations as well as for use by other innovators.

OpenADR 2.0b appears to be aligned with attributes to enable innovation, but it is still early in its maturity. Products are just now being certified and projects and demonstrations are just getting underway that will help to understand how it may get adopted and enable innovation.

It is important to include a transparent standards development process in this convergence of IT and OT systems of the electric grid and consider the needs of all stakeholders – producers, consumers, and innovators. Industry feedback and contributions will ensure we minimize use of proprietary interfaces that require customization and prohibit innovation in this important time in the history of the grid. By developing the right standards, we can ensure the electric grid enables innovation for another 100 plus years.

About the authors

Matt Wakefield is Director of Information and Communication Technologies at the Electric Power Research Institute. He has over 25 years of experience in the electric industry and his responsibilities include furthering the development of a modernized grid through application of standards, communication technology, integration, and cyber security.



Ron Cunningham is an IT Enterprise Architect at American Electric Power with 40 years experience in the electric utility industry with the last 34 years in Information Technology providing general engineering application development and support, customer system support, computer/telecommunications research and development, Internet/intranet web-enabled services/support, security, including the last 24 years in IT Architecture and the last 6 years focused on the smart grid both on internal AEP SG projects and OpenSG and SGIP PAPs and SGAC work efforts.

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Pacific Gas and Electric Company Achieves Millions in Annual Savings with Intelligent Substation Design

By Victor Alverez

The Smart Grid Tsunami

Like so many utilities with aging infrastructure, Pacific Gas and Electric Company (PG&E) needed to modernize its substations and boost service reliability. "As we began a massive, multi-year smart-grid project to address these issues, we knew it would be difficult for our substation design team to keep up with the volume of design projects using our traditional, manual design process," explained Alexander Liang, senior design engineer at PG&E. "With over 1,000 substations in our electric system, we needed to work faster and smarter – so we turned to Bentley Systems for help." A long-term Bentley customer and one of the United States' largest electric and gas utilities, PG&E is based in San Francisco, California, and has over 22,000 employees. The company provides natural gas and electric service to approximately 15 million people throughout a 70,000-square-mile service area in northern and central California.

Reaching the Limitations of Early CAD Technology

PG&E's substation design practice had remained fundamentally unchanged since the 1980s when the company adopted computer-aided drafting (CAD). While CAD initially increased productivity, inefficiencies remained because of the two-dimensional, graphics-only nature of early CAD technology. Consisting of only vector lines, shapes, dots and text, CAD drawings lack any intelligence about the physical entities they represent. For PG&E, this meant that for each substation project, designers had to manually create, maintain, and update designs across countless 2D drawings. "We would draft each and every view pertaining to an outdoor arrangement of equipment," explained Liang. "We'd start by drawing up the plan view and then proceed to draw elevations and sections, each time relying on our experience to figure out what each view should look like." In an effort to save time, designers often copied drawings from other projects, but if these seed drawings were incompletely or incorrectly adapted, the new project was fraught with errors. Furthermore, whenever a design change was made, it had to be manually propagated across all impacted drawings. "This was one of the main drawbacks of unintelligent CAD design – the excessive time people spent manually drafting and updating various views of the same equipment," continued Liang.

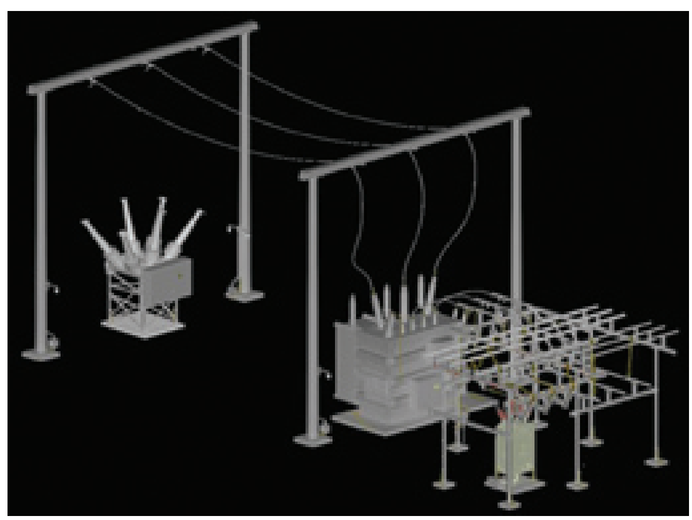


Fig. 2: An intelligent 3D model integrates 3D Physical and 2D electrical design

Inefficiencies were not limited to the drafting process. To create a bill of material for a given project, designers had to visually inspect physical arrangement drawings, count equipment and measure conductor and conduit lengths. The information was then entered into a separate system for procurement. "This manual process was time consuming, inconsistent, and prone to error," said Liang.

Leaping Ahead to Intelligent Substation Design

Given these limitations, management determined that its existing substation design process would make it difficult – if not impossible – to meet the demands of the smart-grid project. "We needed design technology that could help us accelerate substation design projects while significantly improving quality and accuracy – and reduce the overall cost of our substation engineering design and construction," explained Amir Mohebbi, manager of substation engineering at PG&E. They looked for a solution and ultimately chose the only integrated software product for intelligent electrical and physical substation design.

PG&E worked with Bentley to review their existing design process and define requirements. "Our analysis revealed that the software could indeed help us improve productivity and quality while preserving important design processes," said Mohebbi. "Equally important, we could deploy it cost effectively." Bentley consultants began the process of configuring the technology to meet PG&E's specific needs.

They defined new design workflows and built a library of intelligent symbols, devices, and 3D models that designers could pull from and incorporate into designs. Onsite training of designers was vital to ensuring a smooth transition from 2D to 3D site design. And in about six months, Bentley Substation was put into production as the primary design tool used for all projects.

Transforming the Design Process

PG&E designers were able to switch their focus from drafting a set of drawings to constructing an intelligent 3D substation model. Because the software has a database running behind the CAD engine, designers can pull from a growing library of digital 'parts' stored in the database and place them into an arrangement – a 3D model that encapsulates all possible views of the substation design. Everything that gets placed into a design has information relating to that particular piece of equipment.

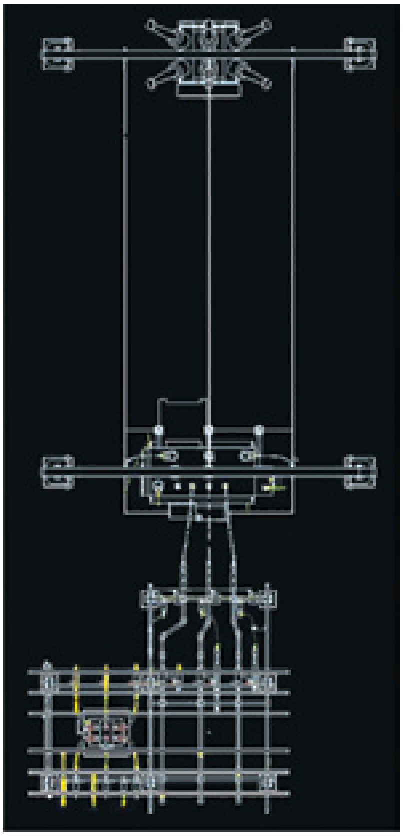


Fig.3: Accurate 2D construction views are now created automatically from the 3D model

Producing accurate 2D construction views is a quick and hassle-free process. According to Nam Trinh, senior design engineer at PG&E, who together with Liang helped transition the company to the new system, "Now, the designer only needs to assemble equipment once in the 3D design and then take snapshots of necessary views." Any changes designers make to the 3D model after the views are taken are automatically reflected across all views. So if a designer edits the properties on one drawing page, for instance, all other drawings containing this equipment are updated instantly, since they are all linked.

40 Percent Faster Design Time

Results from the first five projects developed using Bentley Substation showed a 40 percent reduction in physical and electrical design time. With the average project requiring 52 drawings and each drawing previously requiring approximately 24 hours of manual drafting, the projected savings add up to over 500 hours per project. PG&E estimates this will result in USD 4.7 million in annual savings when averaged across 120 substation projects completed annually.

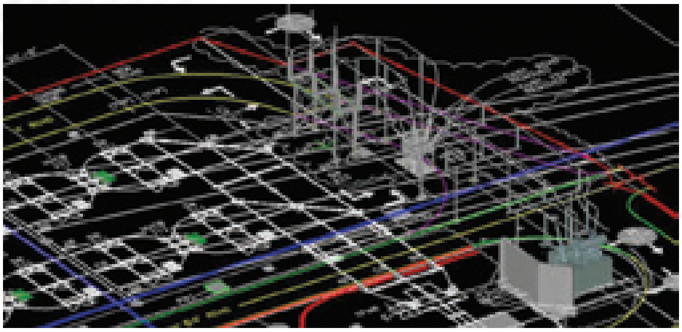


Fig.4: For brownfield design, legacy vector and raster drawings are combined with 3D equipment models

productivity, enhanced design quality, and lower costs are expected benefits of ProjectWise. PG&E is well positioned to sustain and grow its network of substations and realize its smart-grid vision: *provide customers safe, reliable, secure, cost-effective, sustainable, and flexible energy services.*

Fewer Errors and Higher Quality Drawings

PG&E experienced a dramatic reduction in the total number of errors in substation designs. Physical layout drawings are more accurate because they are derived from the intelligent 3D substation model, and schematic drawings have fewer errors thanks to the use of intelligent symbols. "Since relays and other electronics are predefined in symbology and device families, duplicate contacts are prevented, and the correct stud numbers are used," said Trinh. Additionally, automated numbering prevents the same wire tag from appearing on different wires.

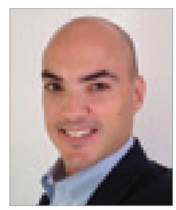
Another benefit of Bentley Substation has been an overall improvement in drawing aesthetics and quality. Previously, these attributes could vary significantly depending on the designer and level of experience. A new level of consistent quality has been achieved by dramatically reducing manual drafting and enforcing PG&E design standards. PG&E estimates that the increases in engineering drawing accuracy, quality and efficiency enabled by Bentley Substation deliver average construction savings of 40 labor hours per substation project, or USD 1 million in additional annual savings across all substation projects.

Faster and More Accurate Bills of Material

PG&E also saves time by automatically generating bills of material for each project. "Each component placed into a substation design has a part number associated with it," explained Trinh. "Bentley Substation keeps track of where and how many of each part has been placed so we can quickly run a report on equipment, sorted by part number, for an accurate bill of material."

Positioned to Deliver the Smart Grid

Bentley Substation is in full production mode at PG&E. Over 85 engineers and drafters have been trained, and the software supports all greenfield and brownfield projects. "Bentley Substation V8i and their professional services have exceeded our expectations in terms of delivering outstanding value," said Trinh. "Bentley's ongoing development and support has helped Pacific Gas and Electric Company meet its goals and provide twice the amount of engineering services with our current staff." PG&E is now deploying ProjectWise, Bentley's engineering content management and project collaboration software, to improve management of the project files created in Bentley Substation. Increased



About the author

Victor Alvarez is a product management and product marketing professional with over 18 years of experience in high-technology environments. He is Senior Manager, Applications Advantage at Bentley Systems where his responsibilities include the company's utilities, communications, electrical, and mining product lines. Victor holds an MS in Systems Architecture and Engineering from the University of Southern California and an MBA from the UCLA Anderson School of Management.

The Case for Storm-Hardened Switchgear

By Thomas P. Trayer, Sr.

Central Lincoln People's Utility District storm-hardened switchgear weathers the elements to help power NOAA's new Pacific Fleet Headquarters; 6-way SCADA VFI with high-speed automatic transfer to provide reliable 15 kV power distribution in a corrosive salt air coastal environment of high moisture and humidity.

The National Oceanic and Atmospheric Administration's Marine Operations Center-Pacific (NOAA MOC-P) provides nearly 41,000 square feet of state-of-the-art LEED-certified offices and warehouses supporting the agency's Pacific Fleet operations. Situated adjacent to Oregon State University's Hatfield Marine Science Center at the head of Yaquina Bay, the new MOC-P facility in Newport, Oregon (Figure 1), is home port to four NOAA research/survey ships as well as supporting five other vessels operating out of Alaska and Hawaii.

Figure 1. The NOAA MOC-P facility in Newport, Oregon provides global communications and high-performance computing operations on a 24/7 basis.

Mission-critical operations demand high power availability

Since 2011, the Marine Operations Center has not only provided administration, engineering and maintenance for NOAA's Pacific fleet, but a host of other mission-critical operations underscore the high value of this facility to the maritime operations of the entire Pacific Rim. This includes, but may not be limited to:

- Producing nautical charts
- Deploying and maintaining buoys for gathering oceanographic information, weather data and generating tsunami warnings
- Managing commercial marine fish stocks
- Collecting data relative to climate and protection of marine life, coral reefs and historic shipwrecks

In the performance of its routine activities, the NOAA center's need for global communications and high-performance computing underscores the demand for reliable power from the local utility to the facility on a 24/7/365 basis. Complicating matters is the environment in which the facility operates. With an average annual rainfall of almost 70 inches, Newport is also no stranger to dense coastal fog, temperature variations, and other coastal weather phenomena. Corrosive salt air environments, too, pose special challenges to utilities in keeping the switchgear and other equipment running at peak performance under operating conditions that often exceed manufacturers' specifications. This was part of the challenge faced by Central Lincoln People's Utility District (PUD) during the construction of the new NOAA facility in the area known locally as South Beach.

Central Lincoln connects the Marine Center to the grid

Founded in 1943 in Lincoln County, Oregon, Central Lincoln PUD is sourced primarily by hydroelectric power from the Bonneville Power Administration dams on the Columbia River and its tributaries. Now serving over 34,000 residential and 4,000 commercial customers over a 700 square mile service territory, Central Lincoln PUD was faced with extending its power distribution line from an existing substation to the new NOAA facility.

"Shortly after the Port of Newport was selected to be the new home port for the NOAA Pacific fleet, Central Lincoln was contacted about the new facility's need for highly reliable, underground electric service," says Bruce J. Lovelin, Chief Engineer/Systems Engineering Manager for Central Lincoln PUD.

Brandi, Miss June
Open for
Pin-up

RECIPE Greg's Favorite Basic Barbecue Rub*
Sprinkle on pork, beef, chicken or even salmon. Cook immediately or for an even richer flavor let marinate for 2-4 hours.
INGREDIENTS
1/4 cup coarse salt (kosher or sea)
1/4 cup (packed) dark brown sugar
1/4 cup paprika
3 tablespoons freshly ground black pepper
1 tablespoon garlic powder
1 tablespoon dried onion flakes
1/2-1 teaspoon cayenne pepper
1/2 teaspoon celery seeds
DIRECTIONS
Combine all ingredients and stir or whisk to mix. Transfer to a jar, cover, and store away from heat and light. The rub keeps for several months. MAKES 1 cup.
Grilling. A smoking hot girl. Pushing metering products?
Yep, we went there.
Why would we do just about *anything* to get your attention?
Because converting to low-voltage metering is ***critical!*** Lives are at stake. Not to mention revenue.
When you meter at low voltage through our guaranteed* VT Pack™, you'll…
• Greatly reduce risk of flash-over, employee injury or death
• Virtually *eliminate* costly meter failure
• Eradicate AMI/AMR signal loss errors
• Protect against lightning surge
• Cut transformer install time to a fraction
• Regain revenue lost to signal errors and meter faults
You'll wonder why it took you so long to notice. But don't thank us …
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The utility's existing switch providing three 200A three-phase ways was deemed insufficient to supply adequate power to both existing customers and the new facility from the same substation. What was needed was a solution that could not only handle the increased power load but provide ruggedized, longer-life operation suitable to Newport's harsh environmental conditions. In this case, 'storm-hardened' switchgear was the answer.

What does it take to 'Storm Harden' switchgear?

While no 'official' classification yet exists for this category of switchgear, a working definition I am comfortable with – "actions taken to secure a system against the ravages of unusually strong storms" – speaks to the need for ruggedizing equipment design, both mechanically and electrically, to withstand extreme environmental conditions while operating reliably over an extended service life. In terms of severe weather impacts on the switchgear itself, the essential hardening elements described below would provide similar levels of survivability for what Trayer Engineering calls 'hurricane and inland storm-rated switchgear.'

Figure 2. Most electrical switchgear is designed for operation in relatively benign outdoor environments. Classic failure points include bolts, door gaskets and other areas where liquid or particulate ingress can destroy the switch or breaker circuitry.

As opposed to non-hardened gear (Figure 2), there are five important elements that contribute to storm-hardening the design of medium voltage switchgear for both pad-mount and below-grade installations:

- ***Corrosion Resistance*** – under hazardous conditions, mechanical degradation caused by corrosion can cause a unit to fail in less time than that projected by a manufacturer. Under 'normal' conditions, ordinary mild steel, even if painted, will corrode and fail. It cannot stand up to exposure to chemical attack, whether from the sea or even fertilizers from agricultural use or domestic lawn sprinkler runoff. Type 304 surgical stainless steel, an Austenitic alloy containing 18 to 20 percent chromium and 8 to10 percent nickel, should be used for enclosure fabrication because of its superior corrosion resistance
- ***Welded Seam Construction and Hermetically Sealed Cavity*** – welded seams provide greater integrity than bolted enclosures that are susceptible to water and particulate ingress through leakage as the equipment ages. Hermetic sealing prevents the loss of insulating mediums such as liquid and gas. A truly sealed cavity will meet an IP68 rating for solids and liquids.
- ***Functional Submersibility*** – even if a welded tank is able to survive a storm surge or heavy winds, mechanical and electrical components such as controls are at risk of losing their functionality, rendering an entire unit, and even grid, obsolete. All componentry, such as SCADA controls and motor operators, must be able to survive adverse conditions
- ***Robust Electrical Design*** – critical internal components, such as switches and interrupters, must be able to survive multiple concurrent fault and overcurrent conditions, such as those present in storms and natural disasters. Vacuum bottle technology greatly reduces the risk of catastrophic failure.
- ***Ease of Operation*** – protecting the lives and wellbeing of the line crew operating high voltage equipment is crucial to the design of switchgear. While working in low visibility or adverse weather conditions, it is important that equipment is clearly labeled, easy to operate and built with safety features such as visible disconnects that allow for a visual indication as to the status of the unit.

Figure 3. Trayer 3805 series medium-voltage electrical switchgear installed by Central Lincoln PUD at the NOAA Pacific Fleet Headquarters provides high-speed automatic transfer and double-sided access. The unit's corrosion-resistant 304 stainless steel enclosure requires no maintenance and prevents rusting in harsh marine and inland storm environments. Note placement of boulders as a landscape barrier to protect the pad from vehicular traffic.

Operational characteristics

Also shown in Figure 3, the switchgear takes advantage of the corrosion resistance provided by its Type 304 stainless steel enclosure that prevents rusting and requires no maintenance, even in harsh, salt air coastal environments like Newport.

Operationally, the unit's primary feeders consist of two switchable 600A ways – one closed and one open during normal operation. A major advantage of having both power feeds coming from the same utility substation, as opposed to separate substations, is the seamless transfer that results from the phasing being identical on both feeds.

The switchgear's fully automated supervisory control and data acquisition (SCADA) switch performs high-speed automatic transfer of the primary power feed circuits to the secondary source in just under 10 cycles – well within the normal ride-through of typical electrically powered equipment today. In addition to open mode, closed transfer mode is also selectable by the user. This allows transfer back to the primary source after power is restored. Other performance characteristics of the 15 kV liquid-insulated switch include:

- Two switched ways; three 200A VFIs and one 600A VFI
- 10,000 load break switch operations at full load, including 8,000 for the VFI
- 600A continuous current and load switching
- One-minute withstand capability at 34 kV (60Hz) for both load switch and VFI
- Standard 95 kV BIL (impulse insulation) for 15 kV-rated switchgear

Fine-tuning the transformer protection relay

Of note in this application is how the switchgear's SEL-487E control unit, Central Lincoln's preferred relay, has been implemented. Manufactured by Schweitzer Engineering Laboratories of Pullman, Washington, the industry-leading unit was originally designed for classic, high-reliability transformer protection applications in utility substations. However, due to the highly adaptable, I/O-intensive capability of the device, the NOAA facility application represents the first known use of the -487E for new, highly specialized distribution automation functions that were neither considered by the manufacturer, nor previously implemented in the industry.

The customization of the -487E's firmware takes advantage of the control unit's ability to simultaneously protect four different three-phase circuits. In operation, this allows the same control platform to provide high-speed transfer functions, fiber or radio communications, an optional GPS clock and true synchro-phasing to ensure that closed transitions for both feeds are completed in exact synchronicity relative to the phasor.

"The unit has been in operation for about a year and a half, and Central Lincoln engineering staff and operations personnel are all very satisfied with the performance of the switch," Chief Engineer Lovelin explains. "Electrically it allows us the flexibility to serve the critical area loads from two sources."

Conclusion

Central Lincoln PUD recognized the need for storm-hardened switchgear to meet the requirements of the expanded NOAA facility in Newport, OR. The switchgear provides a reliable and long-term solution in coastal environments like this but also offer long-term reliability whenever the equipment may be subjected to wind, dust, flooding, and other common conditions.

About the author

Tom Trayer is Northwest Regional Manager for Trayer Engineering Corporation. He has over thirty years of education and experience in the manufacturing, engineering and application of medium voltage switchgear.

Managing Big Data: Challenges and Winning Strategies

By John McDonald, Board Chairman, SGIP 2.0, Inc.

In the digital era, grid modernization involves the addition of devices and systems that produce data – and lots of it. That trend inevitably leads to the use of apt terms such as 'Big Data' and the colorful, if daunting, metaphor 'tsunami.'

Pertinent questions thus arise from those charged with a utility's technology roadmap:

- How can a utility manage, protect, and extract value from Big Data?
- What approaches offer investment protection?

The answers, taken together, are simple, though not necessarily easy. A holistic, standards-based approach to grid modernization that relies on an open architecture will offer the best means of data management, protection and value creation, while ensuring that related investments maintain their value. Supporting this mission and providing guidance is the Smart Grid Interoperability Panel 2.0, Inc.'s (henceforth SGIP) raison d'être.

Pursuing a holistic approach to these related objectives, however, requires a utility to transform itself as well, in order to optimize the business case for grid modernization and align operational and enterprise processes with the benefits that accrue from this path.

The fundamental concept here, of course, is interoperability – enabling devices, systems, and databases to talk to each other, with backwards and forwards compatibility. Another notion is equally important – ensuring that personnel in operations and the enterprise can securely access all pertinent data in a comprehensible form.

Enter: SGIP

SGIP, where I serve as board chair, was birthed by the National Institute of Standards and Technology (NIST) in 2009. It became a member-driven and-funded organization in 2013, placing the power industry's destiny into its own hands.

SGIP, along with other organizations such as NIST, has been working to guide the power industry to an interoperable future. We are accomplishing this task by attracting the widest possible membership and following a methodical process of identifying useful, existing standards, and gaps in those standards, and coordinating standards development organizations' work to harmonize the industry's path forward.

The path forward in the context of Big Data management, protection, and applications includes the adoption of the Common Information Model (CIM) and other pertinent standards – the focus of this article. I'll describe the thinking behind such a solution, articulate the nature of Big Data's management and benefits, and provide an illuminating case study from DTE Energy on the adoption of the CIM.

The nature of Big Data

Smart Grid largely focuses on the distribution system, where intelligent electronic devices (IEDs) are proliferating in substations and on the network's feeders. IEDs range from smart meters to voltage, current and fault sensors to phasor measurement units (PMUs). IEDs are acquiring greater functionality as their prices drop, so this trend will continue. Grid operators must extract full value from them to optimize the business case for their implementation.

IEDs generate both operational and non-operational data. Often they are installed by operations technology (OT) staff seeking operational data to run the grid. OT staff may not be aware of IEDs' value in generating non-operational data for enterprise use or, due to cultural factors, may not want enterprise information technology (IT) staff involved. But failure to exploit both data streams for the utility's overall benefit leaves up to 80 percent of the IEDs' potential value on the table.

In a holistic approach to grid modernization, an organization must exploit non-operational data to extract full value from IEDs. In fact, IEDs' generation of non-operational data is increasing as vendors seek to differentiate their products by adding new functionality. All stakeholders within the organization, particularly enterprise business units, must have access to non-operational data – thus the goal of holistic data management.

The identification, extraction, routing, and use of operational data has been clear for some time. The role of non-operational data must catch up. Be forewarned: exploiting non-operational data will require OT/IT cooperation – a fundamental, historic challenge, but an opportunity for de-siloing.

To be useful, non-operational data must be collected and routed across the firewall to an enterprise data repository, connected to an 'enterprise data mart' or 'virtual data mart' accessible to business units for value creation. (By 'virtual' I mean a federated data server, which sits on top of and is logically linked to existing data repositories.) One major benefit is a switch from time-based to condition-based maintenance and the ability to anticipate equipment failure before it impacts service, saving time and money, and contributing to reliability.

Now, add the need to encourage and analyze data from social media initiated by customers who may report or even photograph outages and their causes and integrate that into the two, aforementioned data streams. Perhaps we should call this emerging area 'Big Data Plus.'

Drivers for managing Big Data

Operational data, of course, is required for maintaining the grid and it supports energy management systems, distribution management systems, and outage management systems as well as the applications that ride on them for greater reliability and improved efficiencies. Non-operational data can further enterprise goals for energy efficiency, load shaping and capital deferral, to name a few benefits. Making meter data accessible to customers may be a regulatory mandate, but it also supports demand response, dynamic pricing, and other programs related to efficiency and reliability.

Open information architecture

Open information architecture is fundamental to our topic. Typically it is transparent, published, and based on industry standards. The obvious benefit is that it can be modified and has the ability to accommodate the widest range of technologies, software, and applications that come along. Consequently, it is a foundational element that offers investment protection.

It wasn't until the 1990s that the power industry grasped the value of open architecture and standard data links. It precluded vendor lock-in, which promised to hold down costs. It offered the basis for a modular, multi-vendor approach as well as being upgradable. With the industry's embrace of the CIM, reflected in the standards IEC 61968 for generation and transmission and IEC 61970 for distribution systems and DMS, software, too, matured.

An open architecture offers the foundation for two levels of applications. One is local in nature, by which I mean distributed intelligence in the control center or in substations and out on distribution feeders. Local applications work based on a subset of the entire system's data. The other level consists of centralized, enterprise-wide apps, which operate using the superset of system data.

A hybrid arrangement that incorporates both centralized and distributed intelligence and applications offers the most flexibility, speed and value. Local, distributed intelligence and applications drive automated responses to grid conditions and free up data network bandwidth and central processing for higher priorities. The centralized approach can drive automation as well, but also includes human operators when circumstances merit it.

Solutions: CIM, other pertinent standards

The CIM is fundamental to our focus here. It is an open standard for representing power system components originally developed by the Electric Power Research Institute (EPRI). It has become a series of standards under the aegis of the International Electrotechnical Commission (IEC).

Those CIM-related standards include IEC 61970-301, a semantic model that describes the components of a power system and the relationships between them. IEC 61968-11 extends this model to other aspects of software-based data exchange, including asset tracking, work scheduling, and customer billing. IEC 62325-301 applies to data exchanged between participants in electricity markets.

The CIM illustrates the strengths of the open architecture, industry standards and software integration approach pursued by SGIP. For instance, when a utility purchases an EMS for generation and transmission systems from a vendor, it typically comes with a suite of applications. If the utility wishes to add another application, say, optimal power flow (OPF), from a different vendor, it may not be easily integrated because the databases setup by the EMS are proprietary – unless the CIM is implemented.

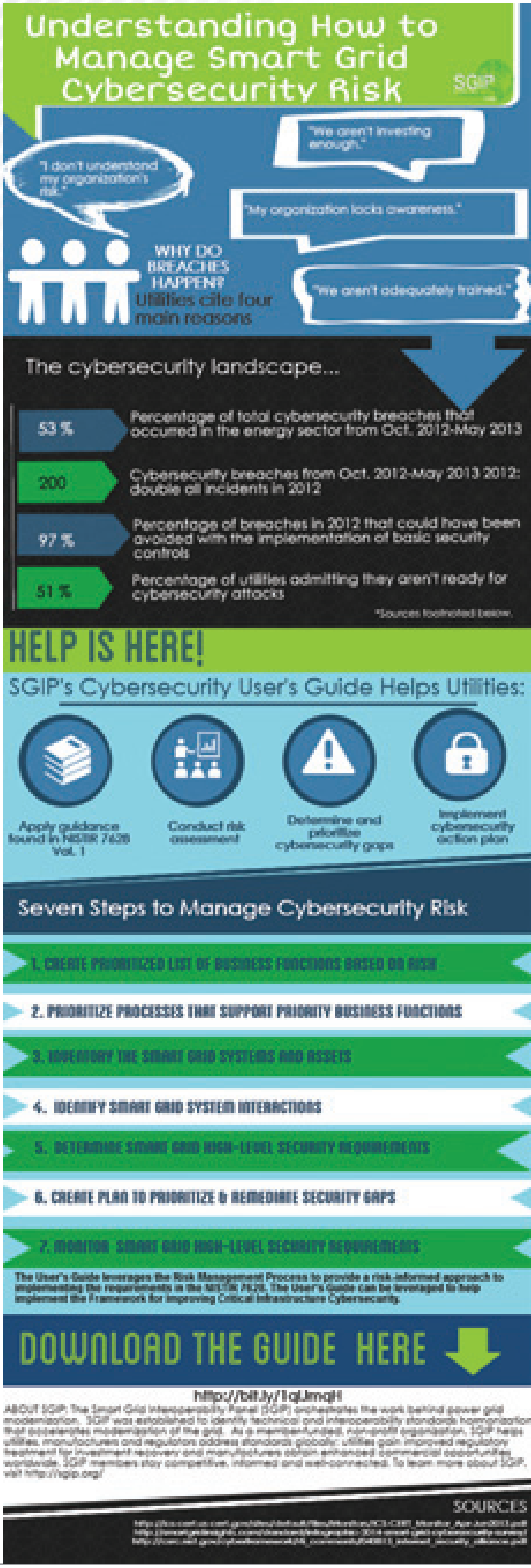
That's because each software app has three parts: input, algorithm (for processing), and output. The means for input and output are structured based on the related databases. If the databases have a proprietary structure that limits the choice of applications, now and into the future, you're stuck. Thus, one key value of CIM is its flexibility in defeating vendor lock-in.

A CIM 'connector' can serve as an interim solution. An EMS supplier can keep its proprietary, real-time database structure for performance reasons, but take this real-time information and the information about the power system network model out of the proprietary database and deliver it to an industry standard format – in this case, the CIM – and the CIM connector allows the use of any application that complies with the CIM format.

Standards for data security

Effective management of Big Data, of course, includes security. Among the 16 foundational standards identified by NIST are three that figure in data security, including:

- AMI-SEC for AMI and Smart Grid end-to-end security
- IEC 62351 for information security for power system control operations
- IEEE 1686 for the security of IEDs



Further, in response to President Obama's Executive Order 13636 in 2013, NIST has created a voluntary, iterative *Framework for Improving Critical Infrastructure Cybersecurity*, released this past February. This follows on the heels of NIST's NISTIR 7628 – Guidelines for Smart Grid Cyber Security, issued in four volumes beginning in 2010. (The Introduction to NISTIR 7628 was written by the original SGIP's Cyber Security Working Group.)

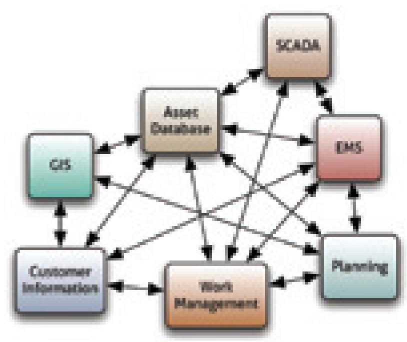
In support of NIST's efforts, SGIP has issued or is currently producing numerous deliverables. The NISTIR 7628 Users Guide is available now and it covers implementation of cyber security practices detailed in NISTIR 7628's first volume. SGIP currently is mapping NISTIR 7628 to the Framework and producing three related white papers, including a case study on the risk management process (RMP) and papers on defense in depth and cloud computing. We are working on a privacy awareness self-assessment tool as well.

Case study: DTE Energy

Nearly a decade ago, DTE Energy recognized the inherent limitations of point-to-point, custom integrations, which includes a high cost in time and money. DTE sought to ensure that future technology additions, including advanced metering infrastructure (AMI), would be scalable, maintainable, secure, and able to evolve as related technology changed. (Headquartered in Detroit, DTE's regulated subsidiaries, DTE Electric and DTE Gas, together serve more than 3 million residential, business, and industrial customers throughout Michigan.)

After winning a stimulus grant for AMI in 2010 for its SmartCurrents project, DTE subsequently settled on using an Enterprise Semantic Model (ESM) and supporting architectural concepts such as the Enterprise Service Bus (ESB). The CIM served as the basis for the ESM. The utility established three guiding principles for its work:

1. The CIM – and related standards IEC 61968 & 61970 – is the most pertinent NIST-recommended standard for Smart Grid interoperability and SmartCurrents IT work would be compliant with it.
2. All application interfaces would be based on the ESM, which requires standard names for standard things.
3. A centralized project team would ensure development of ESM-compliant application interfaces.



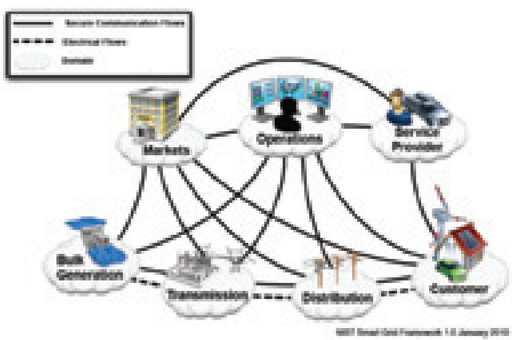
Point-to-point Integration – complex and difficult to maintain

DTE wisely added a key ingredient for success: a governance structure that included executive support, staff training and methodical documentation. The combination of a sound technical approach with effective 'people processes' carried the day.

Sounds good on paper but, of course, there were lessons learned en route to realizing tangible benefits, as documented in a SGIP case study by its Smart Grid Implementation Methods Committee:

- First, just a couple years ago, guidance for such an implementation remained immature.
- Second, changing a utility's information architecture also means changing the organizational culture – and that remains a challenge.
- Third, the upfront disruption and extra effort fueled some pushback from staff.

Additionally, though the CIM fit the electric business well, the fit was not as immediate on the gas side – other information models might be applied. Greater education and training around the benefits of the CIM and ESB might garner more support for such an initiative. Reaching out to external parties and processes can build internal domain expertise, via greater participation in the CIM User Group (a subgroup of the UCA International Users Group) and leveraging outside expertise on the technologies involved gained by other implementations. A fully developed maintenance plan is needed to systematically deal with CIM changes.

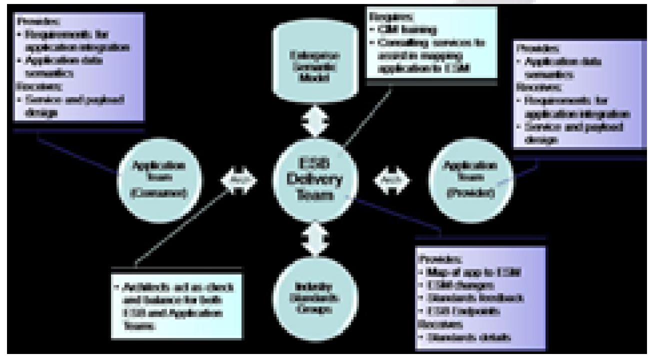


Smart Grid Conceptual Model

Yet incremental successes at DTE began to illuminate the benefits and that provided a positive basis to build on. The cultural shift at DTE remains underway – underscoring the importance of an appetite for change – but with the CIM, ESM, and ESB in place, the reduction in integration timeframes and cost has been notable. While the benefits of the CIM and related standards are intuitive, DTE's case is one of the first to be well-documented, if not fully quantified. (DTE currently does not have an organization-wide method for precisely measuring these benefits, though it is pursuing one.)

In summary, DTE's tangible benefits included reduced time to integration delivery, resulting in:

- Cost savings
- Improved staffing agility, which provides greater efficiency
- The groundwork being laid for potential external interoperability
- A common, cross-organizational vocabulary, which developed through the use of standardized business/IT terms, improving communications and saving time



Relationships between the ESB Delivery Team and the other DTE teams and systems

The time to delivery of services using the CIM and the ESM at DTE has decreased by as much as a ratio of 4 or 5 to 1. An established message structure and cross-organizational vocabulary has eliminated time spent finding agreement on a message structure. There's an upfront cost to implementing the CIM message for the first time, but the total cost of ownership drops because the initial effort is not repeated for every new interface.

Conclusion

As the DTE case illustrates, utility leaders may benefit from addressing their organization's appetite for change prior to potentially disruptive projects such as implementing the CIM. Technology change and organizational change go hand-in-hand; the difficulty in achieving the latter should not be underestimated. In-house, domain expertise in approaching Big Data management should be widely shared. Participation in related, external standards processes is crucial as well.

As the orchestrator of the power industry's standards processes, SGIP benefits from the most diverse possible membership. This helps inform its deliverables, including guidance on managing Big Data and related cyber security practices.

Four years ago, I submitted written testimony to the House Committee on Science and Technology's Subcommittee on Technology and Innovation and what I said then remains true today:

> "As we strive for interoperability across Smart Grid's system of systems, we strive for… getting all the devices and infrastructure to speak a common language, use common interfaces and really work in unison… [This] is a new reality for both suppliers and customers that have traditionally operated in silos… This provides confidence in the technology investment and, ideally, a better return on the investment due to fewer, more easily managed implementations and/or integrations.

> To address awareness and risk aversion, we need engagement, active participation and collaboration among a fully representative set of stakeholders. Being part of the process is paramount to trusting the process and its outcomes. The SGIP embodies and promotes these principles."

In short, industry stakeholders have been empowered to help determine their own destiny through participation in SGIP (www.sgip.org). Join us or buckle up for the ride of your life. Disruptive forces are loose in the land. This demands that we become proactive in transforming our organizations and laying the foundation for future value with a holistic approach to open architecture and the CIM for interoperability and Big Data management.

The means to succeed are at hand. Carpe diem!

About the author

John McDonald is Director, Technical Strategy and Policy Development for GE Energy's Digital Energy business with 40 years of experience in the electric utility transmission and distribution industry. He received his B.S.E.E. and M.S.E.E. (Power Engineering) degrees from Purdue University, and an M.B.A. (Finance) degree from the University of California-Berkeley.

John is a Fellow of IEEE, and was awarded the IEEE Millennium Medal in 2000, the IEEE Power & Energy Society (PES) Excellence in Power Distribution Engineering Award in 2002, and the IEEE PES Substations Committee Distinguished Service Award in 2003. He is Past President of the IEEE PES, a Vice Chair of the Texas A&M University Smart Grid Center Advisory Board and member of the Purdue University Office of Global Affairs Strategic Advisory Council, a member of the IEEE PES Region 3 Scholarship Committee, the VP for Technical Activities for the US National Committee (USNC) of CIGRE, the Past Chair of the IEEE PES Substations Committee, and Chair of the Smart Grid Consumer Collaborative (SGCC) Board. John was the IEEE Division VII Director in 2008-2009. John was on the Board of Governors of the IEEE-SA (Standards Association) in 2010-2011, focusing on long term IEEE Smart Grid standards strategy.

Mr. McDonald was elected to Chair the NIST Smart Grid Interoperability Panel (SGIP) Governing Board for 2010-2012, and is currently the Chairman of the SGIP 2.0, Inc. Board of Directors and a member of the Executive Committee.

Utilities Go Mobile to Improve Operations

New mobile workflow optimization approaches are rewriting smart meter deployment best practices

By Jim Dobbs

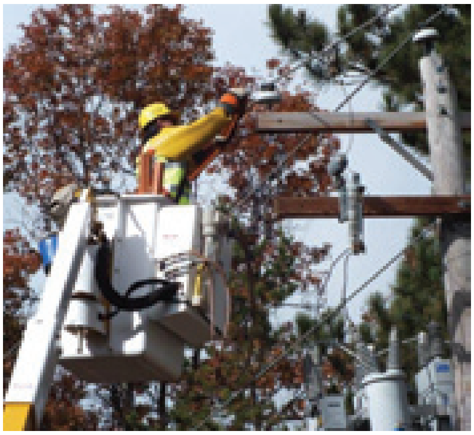
For the typical utility company, two-thirds of total employees are field based. This makes the extension of critical business applications to remote users a key opportunity for productivity improvement and cost reduction. Mobile technologies integrated with back-end systems, such as outage management and work management systems, support the display of maps in the field and help coordinate crew activities, enabling field personnel to view, update and complete work orders.

For example, in the case of outage management, an integrated solution offers field crews the same map view as a dispatcher, establishing real-time, bidirectional communication between the field and the back office. Field crews can update job information, change job and crew status, create new outages on the network, perform tracing, use GPS navigation with automatic vehicle location (AVL) and more. Changes made in the field are instantly visible to the dispatcher.

By integrating functions such as these, and extending information and capabilities to the field, forward thinking utilities are improving operations, from outage to asset management.

Outage Restoration

Severe weather is the leading cause of power outages in the U.S. Consider the state of Wisconsin. The state experiences many outages due to high winds and winter weather. Dispatchers and field crews from utility companies like Wisconsin Public Service (WPS) often deal with trouble calls, such as outages caused by fallen trees or frozen power lines.



In order to deal with these demands, WPS has worked to improve outage management across its service territory. Serving more than 400,000 utility customers and 300,000 natural gas customers in northeastern Wisconsin, WPS uses a configurable, off-the-shelf outage management system (OMS). It features a simple, intuitive user interface with a geographic information system (GIS)-based interactive map, providing effective dispatching, monitoring and operations.

With integrated mobile technologies, WPS extends outage management to the field. Field crews at WPS can see exactly what the dispatchers in the office see. In an instant, they know where an outage is, what may have caused the outage and who can fix it. The even know the location of the nearest technician based on a map view of the electrical and street networks.

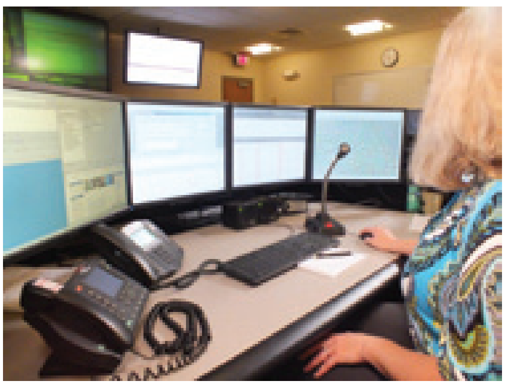
Prior to the implementation of the new OMS in 2006, when a call came into its dispatch center, WPS linemen would have to write their trouble orders on paper forms based on the dispatchers' relayed information. This cumbersome process also left field workers completely dependent on information they received from the dispatchers, causing more radio traffic and less time for the dispatch center and field crews to address other issues.

With the integrated OMS and mobile solution, the process has greatly improved. "The response is quicker for us and it saves a lot of time in dispatching," said Jeff Weller, line electrician at WPS. "We don't have to sit and wait now for another job. It just comes to us instantaneously. It's incredible, the response time."

For the dispatch control center, the system slashes radio traffic and allows dispatchers to handle other tasks. As Dale Klimek, distribution operation supervisor at WPS explained, "Now that we send information to the field crews electronically, our dispatchers are freed up to do other things that we weren't able to do in the past."

For example, during storms, WPS places a lot of focus on the electrical grid and dispatching line crews to storm areas. Before implementation, dispatchers had trouble servicing the WPS gas business while still handling high-priority electrical issues. With the time savings from mobile technology, WPS can serve gas employees and communicate with other customers and business partners, while still addressing the electrical issues associated with weather events.

"[It] allows us to make smart decisions on which crew to send where and to reach the affected areas sooner. It's just a better way to assist our line crews and service our customers," said Deanna Vanlannen, distribution dispatcher at WPS.



Employees of WPS aren't the only ones reaping the benefits. Customers are seeing faster power restoration times than ever before.

"I think customers' expectations in all industries are different than they were years ago," said Klimek. "So, as customers, even as employees, we don't like the power to be out for very long periods of time. If we can use technology to get electricity back on and restored quicker, customers are happier. Mobile computing is going to allow us to do that, and that is what our customers want."

Managing Assets

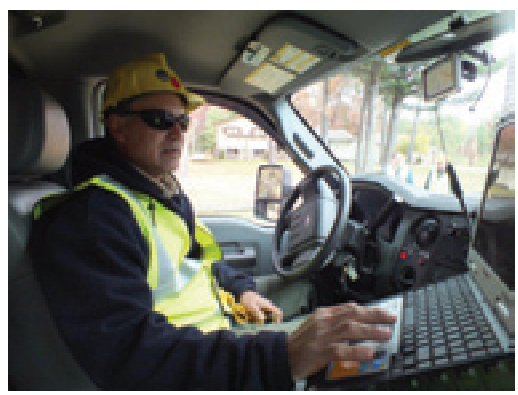
Similar benefits can be achieved when mobile capabilities are combined with asset management. Many utilities struggle with the management of their assets' location, condition and status. These assets, which include distribution poles and transformers along major roadways and small streets, must be tracked, monitored and maintained.

One common challenge for utilities is overseeing the poles and their attachments. Attachments can be utility-owned or foreign-owned assets – such as those owned by cable companies – that are connected to the utility pole or lashed to the conductor, and generate additional weight and stress to the pole.

Typically, agreements exist between the companies that allow the utility to charge for foreign attachments. However, there may not be a defined process for notifying the utility when an attachment is made. Further, due to staff turnover, construction, system changes and the like, these charges are not updated or renewed. A loss of revenue for the utility may result.

Oshawa Power and Utilities Corporation (PUC) in Canada, which serves 160,000 citizens over 145 square kilometers, sought to overcome the problem. When Oshawa PUC migrated to a new platform for geospatial network and infrastructure management, it became necessary to update its inventory of assets, their conditions and mapping locations. Oshawa PUC initiated a project to conduct field inspections of all its assets to validate its GIS to the field and update the GIS with work orders, matching it to the backlog.

Oshawa PUC equipped field crews with mobile applications on Windows-based tablets, enabling personnel to inspect the condition of assets, capture redlines, conduct any repairs necessary, document the work and update the work order. All this is done via XML technology that feeds directly to Oshawa's back office, eliminating paper reports and double-entry of its inspection information. With the solution, Oshawa PUC collected asset conditions and reconciled data on 12,000 poles and 3,200 transformers in six months.



Field crews also used the tablet's camera to capture photos or videos to complement the inspection data. This feature was useful when Oshawa PUC crews audited its utility attachments. Using their GPS-enabled devices, the crews geo-located and catalogued these attachments and the assets they belonged to and matched them with issued attachment reports to its partners.

From Maps to Apps

Some utilities are even incorporating native smartphone and tablet apps as a means for collecting field data. One such organization is Frederiksberg Utility, located in Copenhagen, Denmark, which provides water, sewage, gas and district heating to 100,000 people.

The utility integrates Open Geospatial Consortium (OGC)-standard protocols into its workflows and leverages a native app and GIS and network management software to plan and prioritize maintenance in order to reduce cost.

With the app, Frederiksberg Utility collects data on thousands of physical assets. This simple solution requires minimal time, training and administrative input. The information is gathered in the field, stored in a cloud service and used to update the GIS facility database with tremendous detail. The unique asset information includes images with GPS coordinates attached.

Reducing Waste

An added benefit of these types of solutions is a reduction in paper waste. Utility company environmental programs mainly focus on power generation, transmission and delivery. However, companies can also benefit the environment by adjusting internal procedures, such as the manner in which they manage work orders.

Cobb EMC, an electric membership cooperative, serves approximately 197,000 consumers in nine counties in the U.S. state of Georgia. Consisting of more than 10,000 miles of line, it is one of the largest cooperatives in the country.

Part of Cobb EMC's work involves locating underground equipment before customers begin excavation projects. A typical day for the utility company involved printing 400 service tickets. Those tickets were categorized manually and distributed to field locators in each service region.

With such a high volume of customers, Cobb EMC needed a solution that would increase productivity and eliminate the excessive amounts of paper used each day. Cobb EMC decided to go 'green' and create an application that would allow all service tickets to be received, handled and closed electronically.

Building on top of its customizable network management system, Cobb EMC created a new application, CobbLocate, utilizing its own map in its original data quality. The web service interface component of CobbLocate receives, processes and saves service tickets to the CobbLocate database. After the ticket is saved into the database, it can be dispatched in near real-time.

Dispatchers receive all service tickets and sort them based on the geographic location or the addresses of service boundaries, and then dispatch those tickets to the locators in the field. Locators receive and organize service tickets, locate sites, go out into the field and complete the work.

"In the old workflow, the locating supervisor would receive all the tickets in his email inbox. He would print out every single ticket and then sort out the addresses and hand over the piece of paper to the locators," said Manish Murudkar of Cobb EMC.

Before the implementation of CobbLocate, service managers would spend at least two hours every morning sorting through tickets before any of the locators could go out into the field. Now, "the entire workflow is managed in the CobbLocate application itself," said Murudkar. "Using the application, they can accomplish the same work in less than five minutes."

Cobb EMC's choice to go green has greatly improved productivity and reduced costs for paper and ink.

Conclusion

Success in the field is directly related to the quality of service a utility can deliver. Integrated mobile and back-office systems create more and better opportunities for utility companies to successfully manage outages and assets. By deploying integrated systems and extending those systems onto the latest devices, from rugged laptops to smartphone and tablets, utilities will continue to improve their ability to meet customer demands and keep the lights on.

About the author

Jim Dobbs is executive manager, global communications, for Intergraph Security, Government & Infrastructure. He writes about issues impacting utilities and communications companies, among others.

THE BIGGER PICTURE

BY PHILIP BARTON

Agencies leverage advanced metering infrastructure to enhance the energy 'triple bottom line'

Many federal agencies originally installed an advanced metering infrastructure (AMI) to measure and monitor energy use simply to comply with congressional mandates. In those cases, agencies used the metering system to help identify energy savings opportunities and track performance of the implemented energy conservation measures. Some users have learned that AMI can do much more to help achieve their overall energy goals. Leaders in industries like petrochemical (oil & gas) and semiconductors discovered long ago that AMI can be leveraged to achieve a 'triple bottom line,' which comprises energy efficiency; optimization of energy assets, including renewable energy assets; and increased energy security.

AMI integrates sophisticated meters that measure all utilities with intelligent, two-way communications, energy data management software, and a secure network. To appreciate the benefit of harnessing smart meters into a global, interactive communications network, take a look at the global AMI network installed by Naval Facilities Engineering Command (NAVFAC). In near real time, AMI systems link Navy and Marine Corps bases and facilities worldwide, giving visibility into a large percent of the organization's energy consumption. With an annual utility bill of about $1 billion and requirements to cut energy consumption by three percent per year across the department, the Navy stands to realize significant improvements in monitoring and managing its energy usage.

Bottom Line #1: Energy Efficiency

The data collected by AMI provides NAVFAC with the tools to achieve the first bottom line: energy efficiency. AMI effectively monitors and manages consumption of all utilities: water, air, gas, electricity and steam (WAGES). This calculates the gross BTU per square foot, which allows engineers to precisely research and recommend the highest return for energy savings projects. The information helps agencies like the Navy identify areas in which to improve efficiencies and accurately allocate the cost of energy usage.

Energy consumption granularity serves as fuel for net zero planning, which seeks to produce as much energy onsite as a facility uses, ideally from green sources. The first priority for net zero planning is to find the 'negawatts,' or energy that can be saved through efficiency and demand response tactics. AMI helps pinpoint potential negawatt areas such as machinery left running but not in use, or loads that use energy in an unoccupied building in the middle of the night. Negawatts can account for as much as 10 percent to 30 percent of total energy use.

Bottom Line #2: Optimizing Energy Assets

After determining all possible energy savings opportunities, the next step toward achieving net zero is to apply the most cost-efficient green generation possible – an element of the second bottom line: optimizing energy assets. AMI can help determine the most efficient generation sources by verifying a renewable energy generator's real efficiencies versus its stated efficiencies. Reasons for the discrepancies between the two values can vary widely. One example is a photovoltaic (PV) panel applied or installed incorrectly or placed in a shaded area, resulting in less-than-optimal performance. In another example, a malfunctioning panel in a string of PV panels can disrupt the entire system if not properly metered and maintained. Levels of generation and efficiency vary by manufacturer, but AMI helps ensure that the renewable generation source can fulfill the potential represented by the manufacturer's specifications.

In addition, today's AMI can help agencies optimize their energy assets using criteria like changes in weather as well as occupancy and space utilization. Consider troop deployment: The constant flux in demand driven by troops' deployment and return often renders compiled energy data irrelevant and dated, and in turn does not accurately reflect current needs. Critical loads change day to day, so the instantaneous data available from AMI serves as a vehicle for increasing system stability.

Once energy loads are known, AMI users possess the knowledge to confidently shed the necessary loads. Loads are typically shed in blocks, but this approach can risk over-shedding and disabling critical power loads unnecessarily. A mistake like this at an air base could disrupt all flight line operations.

Bottom Line #3: Energy Security

Rounding out the triple bottom line of AMI is energy security. An AMI provides understanding of the sources and uses of power in a system. Under today's grid protocols, utility generation shuts down during times of power outages. Advocates argue that this is precisely when on-site generation sources, like those in a microgrid, could offer the greatest value to both generation owners and society. A microgrid is an integrated energy system consisting of distributed energy resources and multiple electrical loads operating as a single, autonomous grid either in parallel to or "islanded" from the existing utility power grid. 'Islanding' involves separation or isolation from a utility's distributed system during brownouts or blackouts, acts of terrorism, or extreme weather conditions, thereby improving energy security. Such sources can provide power services when the larger grid system has failed consumers and owners of distributed energy generation systems.

Speed is the key to reliability, and reliability is integral to energy security. Reliable systems with loads metered in real time can react instantaneously to changes in loads and in generation. In addition, increased reaction speed reduces the amount of energy storage needed.

Alternatively, if a system has a static load shed algorithm, an event as simple as a loss of sunlight could trip a trigger that takes a diesel generator offline, sends the system into overload, and ultimately disables an entire system. High speed controls coupled with the right studies, like a transient stability load flow, will minimize or negate the chance that the event will trip the generation assets due to overload. This results in improved system reliability and increases the energy security bottom line.

Energy is a fundamental asset to federal agencies in advancing their core mission. No agency can operate without it. By helping agencies improve energy efficiency, optimize their energy resources and increase energy security, AMI ensures operational resiliency and mission effectiveness.

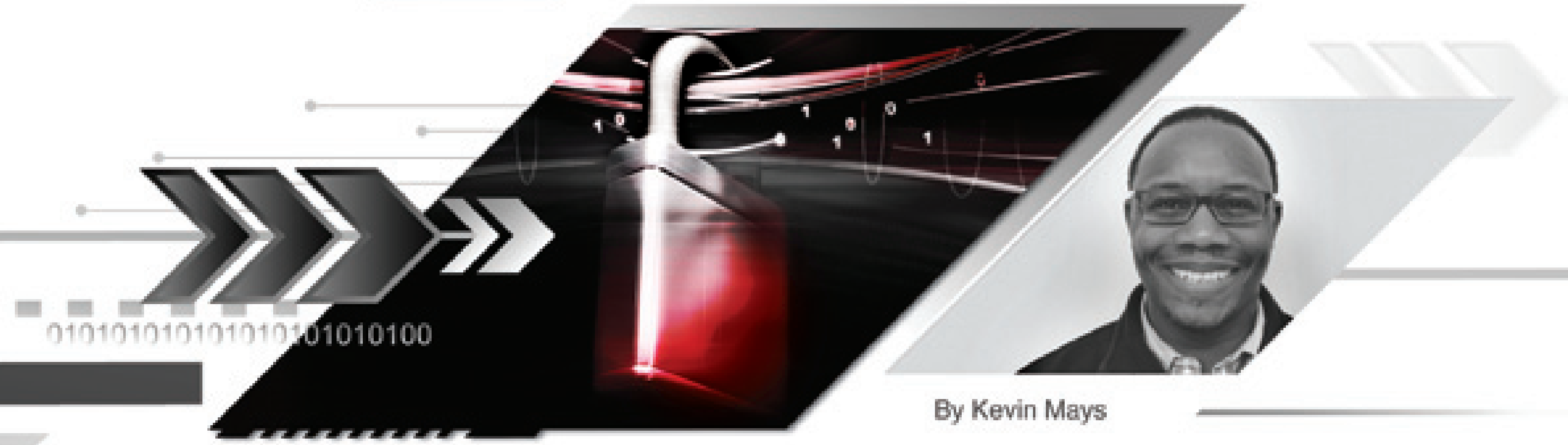
ABOUT THE AUTHOR

Philip leads Schneider Electric's U.S. activity to organize microgrid projects and solutions both internally and externally with partner companies. Since 1998, Philip has led Schneider Electric teams retrofitting entire microgrids or any part of their enabling technology. Enabling technology includes distributed generation, power equipment, engineering services, metering, software and power controls.

From 2009 to 2011, Philip created and directed Schneider Electric's Federal Energy Solutions Business. The Energy Solutions Federal team developed hundreds of advanced metering infrastructure and other energy projects worldwide. Two of the projects were Schneider Electric's first federal Energy Savings Performance Contracts. They are still recognized as among the fastest moving projects in DOE program history.

One of the two was a net zero project that combined 3 MWs of self-funding solar PV inside of an ESPC at 3 USCG bases in Puerto Rico. The self-funding project combined 28 percent savings plus 35 percent renewable energy to reach 63 percent of net zero.

Previously Philip held leadership positions Power Management and Control, as well as Square D Power Services, residing in Nashville, Atlanta and Dallas.



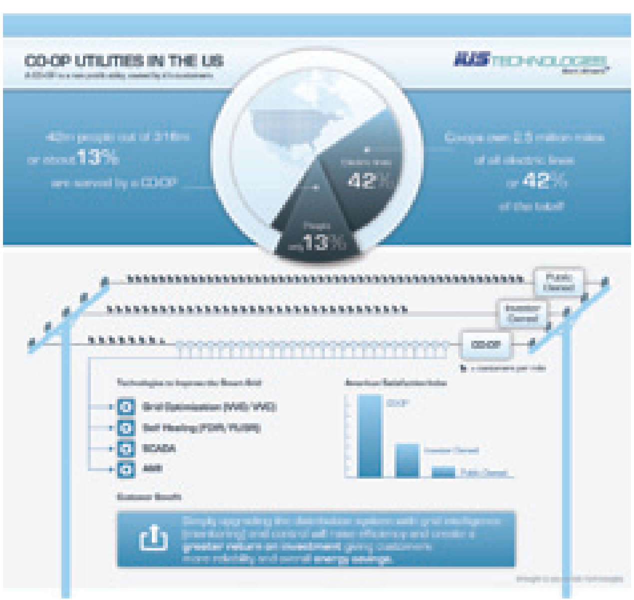
By Kevin Mays

SECURITY SESSIONS

Smart Grids make Good Sense for Rural Co-ops

For most people, the phrase smart grid brings to mind sleek power grid infrastructure or rooms full of engineers in white lab coats monitoring streams of data. Most smart grid installations aren't quite as sexy as those images, but there's an even bigger fallacy surrounding the lore of smart grid technology – that it lives exclusively in the realm of large investor owned utilities (IOUs). That's not true.

In fact, smaller power distribution organizations like co-operatives (co-ops) have just as much to gain by bolstering their efficiencies. Operating over 40 percent of the nation's power lines, co-ops can effect meaningful change to power distribution in the U.S. by adopting smart grid technology. Rural co-ops can realize large gains in efficiency for relatively small spends on this scalable technology and achieve remarkable returns on investment.



Before diving into why co-ops have so much to gain, it is important to understand precisely what smart grid technology is currently capable of. When a grid is referred to as smart, that indicates it contains these characteristics:

- Intelligence: Smart grids rely on a steady stream of data from remote distribution line sensors and monitors to construct an understanding of what is happening throughout the network. In simplified terms, more data leads to greater intelligence.
- Communication: In order for data to be analyzed and used, it must be relayed to a central control center where it can be aggregated with other data to build true intelligence. This process relies on real-time communication with line sensors and other integrated devices.
- Control: Smart grids don't just collect and analyze data, they also react to it. When remote sensors detect conditions that require corrective action, equipment such as capacitor banks, switchgear, voltage regulators, and load tap changers can be activated from the control center to respond accordingly, correcting problems and optimizing line conditions.

Once those three core capabilities are in place, smart grids can really spring into action and start delivering value. New devices are continually under development to expand the capabilities of smart grids, but there are a few key functions that utilities are most interested in. These specific functions fall under the encompassing moniker of *distribution automation* because they can be initiated and adjusted using algorithms without the need for human involvement.

- **Advanced metering infrastructure (AMI)**: Smart meters are the most ubiquitous form of AMI and this is the most customer facing aspect of smart grid technology. AMI allows utilities to remotely meter energy usage without relying on meter reading personnel and service can be remotely activated or deactivated without the need for a site visit.

- **Volt/VAR optimization (VVO)**: Concerned with maximizing power line efficiency and preventing loss, VVO ruses real-time data from power lines to calculate ideal voltage and VAR profiles. With information on load conditions like power factor, active and reactive power, smart grids can adjust how electricity is sent to minimize losses on distribution lines.
- **Volt/VAR control (VVC)**: Somewhat related to VVO, VVC is used to optimize voltage levels on power lines, striking a delicate balance between lowering voltage to minimize waste while producing enough voltage to prevent brownouts. This tightrope walk depends heavily on real-time energy usage information throughout the grid.
- **Secondary transformer monitoring**: Remote monitors can provide information on secondary distribution transformer load, temperature, and insulation oil health. This information alerts technicians when preventative maintenance is necessary and extends the lives of these costly devices, also nipping issues that could cause outages or expensive repairs in the bud.
- **Self-healing**: Smart sensors and fault indicators detect when faults have occurred and control centers are able to respond by using reclosers, switchgear, and capacitor banks to route power from alternative energy sources around them until they can be cleared. When automated, this action can occur before customers experience service disruption.
- **Theft prevention**: An emerging technology that takes advantage of smart grid communication networks is energy theft detection. Using specially designed portable remote monitors, utilities can measure actual energy usage and cross-reference the data with billing records to detect energy theft, even when it occurs directly from distribution lines.

Anatomy of a co-op

Though co-ops distribute electricity in a variety of settings, they are most often associated with rural areas. There are over 863 rural co-ops in the United States, delivering power to just 12 percent of the nation's population – but because co-ops typically service low density areas, they operate more than 40 percent of the distribution lines that cover almost 75 percent of the country's land mass.

This combination of extensive line length and low customer density amplifies opportunities for co-ops to benefit from the efficiencies smart grid technology provides. Rural co-ops face a simple math problem: the overhead associated with each mile of distribution line is the same regardless of how many customers it serves. Since fewer customers equates to less revenue, covering the fixed costs associated with electricity distribution can be a challenge for most rural co-ops.

Without economies of scale through more paying customers, rural co-ops have no choice but to bill higher rates to cover infrastructure costs and capital expenditures. On average, rural co-op customers pay 275 percent more than the national average for electricity. As non-profit member owned companies, the billing rates customers pay for energy usage are directly tied to the costs of acquiring and distributing electricity. Subsequently, they are mandated by their members to operate as efficiently as possible to minimize costs.

Controlled by boards of directors, co-ops are almost always more nimble than IOUs because they do not generally have to go through the bureaucracy of obtaining approval from legislative bodies to change rates or make significant investments in infrastructure. This agility along with pressure from members to optimize efficiency to lower prices positions co-ops well to move quickly on new technology and on upgrades that will reduce costs and increase reliability in the future.

Controlling line losses

The distance covered by distribution lines owned by rural co-ops introduces special considerations. Utilities, co-ops, and municipalities alike face energy losses from line inductance; it's one of the most prominent sources of waste. These losses are typically associated with warm climates because air conditioners rely on induction motors that can lead to large inefficiencies. However, losses from inductance are also influenced by length of line. Rural co-ops that operate long line lengths face this type of inductance on a large scale.

When inductance levels are known, VVO can modify VAR profiles to minimize losses associated with them. Inductance due to line length increases with distance, so the amount of remote sensors required to control this type of loss is much lower than would be required to combat losses resulting from a large number of induction motors running on a relatively short length of line. Rural co-ops can achieve gains in efficiency through small spends by adding line sensing equipment to support capacitor banks that compensate for inductive losses.

Distance complicates keeping the lights on

Inductance isn't the only special issue that long line distances cause for rural co-ops. Technicians at these co-ops also oversee much larger territories than those at urban Intelligent Operation Centers (IOCs), which can make finding sources of outages and other issues difficult and expensive. Any electricity distributor without line sensing infrastructure relies on customer complaints to become aware of outages; but they don't know exactly what is causing the outage and where the problem is located. Technicians must be dispatched to find and correct the problem.

This has been a large source of inefficiency even in densely populated areas, but is amplified in rural locations. When customers are spread out, it is more difficult to estimate where a problem is located based on who is affected. Not only do technicians have longer distances to travel in order to start looking for problems due to their large territories, they also have much longer lengths of line to search for outage sources.

Outages in rural environments take longer to locate and fix, costing technician man-hours and keeping customers in the dark for extended periods. Also, rural technicians have to drive further, burning more fuel and increasing the chances that they will work past their scheduled hours and cost even more money for crossing into afterhours pay scales. Imagine the frustration of a rural co-op member who must wait long periods of time to have power restored while paying almost three times the national average for service.

Truly smart grids are able to heal themselves by detecting faults and automatically rerouting power. For rural areas where multiple sources of electricity are not available, rerouting may not be an option. However, line sensors can greatly improve the efficiency and cost of power restoration by immediately alerting control centers of an outage so technicians can be dispatched before affected customers start calling.

The real value, though, comes from fault location isolation and service restoration (FLISR). Fault circuit indicators not only alert control centers that an outage has occurred, they isolate where the fault is. They can attempt to correct the fault automatically by triggering reclosers to activate and clear the line, which restores power about 80 percent of the time. If the reclosers fail to clear the fault or if reclosers are not implemented, FLISR technology can direct technicians to where the fault is located so they don't have to drive for miles inspecting line.

Industrial loads in the country

Rural co-ops may serve lower density populations, but they also often have different types of corporate customers. Large scale commercial and industrial operations that are served by critical load distribution transformers like manufacturing plants, petrochemical processing facilities, food processing plants, and a wide array of industrial operations are often located in rural areas serviced by co-ops. Heavy load, multi-phase distribution transformers are some of the most expensive and difficult to service devices electricity distributors have, so managing the lifecycle of these capital assets is vital.

Failure of these transformers also has detrimental effects. If such a transformer fails unexpectedly, it could literally mean thousands of people are unable to work and countless dollars are lost until the problem is corrected. Therefore, it is extremely important for co-ops to ensure that these transformers are kept in good working order – but regularly scheduled maintenance can only do so much.

Transformer monitors that are capable of detecting and reporting conditions like load, temperature, and even combustible gas levels are becoming more common and affordable. Monitoring transformers between regularly scheduled maintenance allows co-ops to ensure that this equipment is operating correctly and efficiently. When variables fall out of spec, technicians can respond early, avoiding more costly repairs later and the possibility of unexpected failure. This also keeps critical load transformers operating efficiently and extending their asset lifecycles, which saves members money.

More places for thieves to hide

It is estimated that energy thieves in the United States cost utilities $6 billion every year in lost revenues. As more tamper resistant meters and AMI technology are implemented, energy theft is trending toward sophisticated implementations that tap distribution lines before they are metered. Illegal operations like marijuana grow houses that have the capability to siphon massive amounts of electricity are becoming much craftier and difficult to detect, often going so far as to install their own transformers and underground lines.

Detecting energy theft has largely depended on rather rudimentary techniques like tips, visual inspections, or just plain luck. Professionally installed illegal hook-ups are on the upswing and challenging to detect in any environment, but rural implementations are especially challenging due to high probability of this activity being completed without being noticed by anyone. Once in place, it becomes extremely difficult to find and stop these operations using traditional means.

The best way to detect energy theft is to cross-reference actual energy usage with billed usage, but meters are the only devices most co-ops have to measure real usage. So what can be done when meters are bypassed? Specially designed remote energy monitors are now available that report usage from distribution lines. Many of them are portable, so they only need to be installed until theft is confirmed and stopped. Then, they can then be moved to another location and begin the process again. Using devices like this, rural co-ops can easily detect large amounts of energy theft with only a few monitors.

Increased efficiency passed on to members

Smart grid technology isn't a magic bullet that instantly replaces legacy infrastructure. It is an encompassing term that includes a variety of devices that are scalable depending on specific situations and needs. Rural co-ops can evaluate their grids and make decisions on what technology makes the most sense for them, increasing efficiency without spending more on equipment than they will gain in reducing losses.

Utilities are under pressure from public utility commissions to increase efficiency, decrease emissions, and curb theft, while co-ops are under direct pressure from members to reduce costs and rates. Doing so does not require enormous budgets or robust engineering payrolls. Wisely implemented smart grid technology will certainly result in an appreciable return on investment and satisfy the member mandate to deliver energy as efficiently and inexpensively as possible.

ABOUT THE AUTHOR

Kevin Mays is product/application engineer at IUS Technologies with over 20 years of engineering design, product development, and technical sales experience. He holds a BSEE from Northeastern University and his circuit design and technical expertise was gained while employed at Motorola, Uniden-America PRC, and Maxim Integrated Products.

The Long Road to Improved Utility Storm Planning Begins Here

Guest Editorial 1

By Ellen Smith, R.J. Arsenault, and Conor Branch

Hurricane Sandy made it obvious that electric distribution utilities were ill-prepared to prevent large-scale power outages or quickly restore power to businesses and households. After Sandy, many states and industry groups created special commissions and studies that offered prescriptions to harden the energy infrastructure. However, this past winter's storms, and the lengthy outages that resulted, underscore the fact that these prescriptions could take years to implement and still may be insufficient. The consequences have been severe for utility customers. Not surprisingly, the reputation of the utilities has been damaged, and their customers increasingly are looking for alternatives. If the electrical utility sector does not address its problems, it will lose customers, as well as investors. Utility companies may find themselves short of capital at a time when they need to invest the most. Fortunately, there are some immediate actions these firms can take.

October 2012

Hurricane Sandy, the so-called Superstorm, made landfall near Atlantic City, New Jersey, on Oct. 29, 2012. The storm affected 24 states. The U.S. Department of Commerce estimated that Sandy caused some $50 billion in damage and 100 direct storm-related deaths.

On Oct. 31, two days after Sandy hit, more than 6 million people were without power, including over half the population of New Jersey and a fifth of New York State residents. The duration of the tail – the time during which customers are left without power – would go on and on.

According to a February 2013 New York State Bipartisan Task Force,[1] report on the storm; 'Power for 2.19 million households was out for days, weeks and even months.' The report continued: 'Most local officials expressed dissatisfaction with their local utility company' largely due to a 'lack of communication, disorganization, poor customer service and slow response time.' This disappointment was widely shared and magnified by traditional, digital and social media.

In Sandy's wake, many states convened committees and issued special reports. The consensus was that electric utilities must be better prepared for extreme weather events. The reports stressed the need to:

- Build resilience by selectively burying power lines, improving tree trimming and creating redundant distribution capabilities
- Invest in enhancing and modernizing infrastructure by deploying smart meters and other technologically advanced distribution systems
- Improve resource-sharing agreements among utilities and governing authorities across states, where one state agrees to send its workers to another state in greater need
- Insist that regulators hold utilities accountable for storm response targets and assess heavy fines and fees in cases of noncompliance

Winter 2013-2014

On Feb. 5, 2014, the Philadelphia region was hit by a major snow and ice storm (PA Snowstorm), causing Philadelphia Electric's (PECO) second-largest outage ever and leaving approximately 623,000 of its customers without power. Altogether, greater Philadelphia area utilities left more than 712,000 customers in the dark. Two days later, PECO still had not restored service to 290,000 customers. Some customers were without power for more than a week.

Despite the well-intentioned and worthwhile suggestions and directives that emerged from post-Sandy task forces and commissions, actual improvement in extreme weather utility response is hard to document. Today, the nation's electric system seems scarcely more resilient than it was two years ago. After significant storms, the peaks (the number of households and businesses that lose power) are just as high; the tail is just as long (see Figure 1).

The Long Road to Improved Utility Storm Planning Begins Here

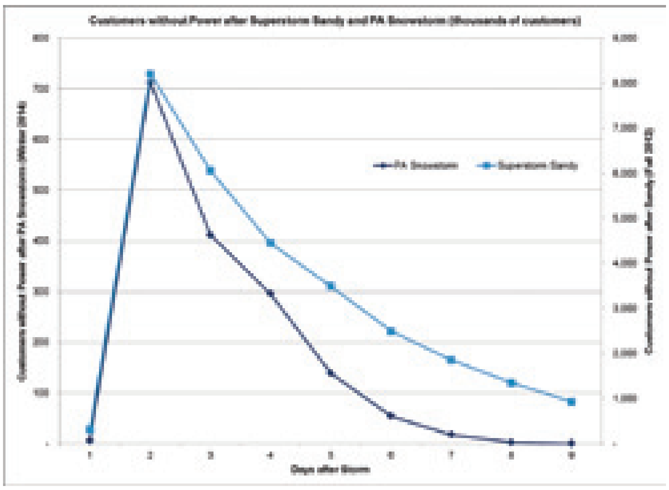


Figure 1: Sources: Atlantic City Electric (ACE), Delmarva Power, Maryland Public Service Commission, PECO, PPL Electric Utilities Corporation (PPL) and Public Service Enterprise Group Incorporated (PSE&G) websites.

The human cost is obvious. However, the PA snowstorm also drained between $80 million and $120 million from PECO's coffers. Thus, with a combination of heavy financial impact and strong customer dissatisfaction – the inevitable consequences of outages, especially long ones – a perfect storm, so to speak, is brewing for electric utilities.

It is not surprising that more customers are deciding to provide for their own energy needs. As more customers self-provide – whether through micro grids, on-site generators, solar technologies or other means – the number of people paying for the existing electrical infrastructure will decline, reducing revenues for utilities. Those reductions will drive *up* the utilities' cost per customer, decreasing margins and the capital available for investment in infrastructure modernization and other activities that might lower the peak and shorten the tail of extreme weather events. Those investments could include burying power lines, replacing old poles or implementing aggressive tree-trimming programs.

In short, electric utility companies are caught in a bind. Enduring underperformance creates a huge threat to their revenue bases and business models. By many metrics, the financial health of investor-owned utilities has suffered. According to the Edison Electric Institute (EEI), energy sales declined between 2002 and 2012, while costs and debt increased during that same 10-year period.

Missing the Big Picture

Post-Sandy reports looked to the future but offered few suggestions for fixing the present. And the present has its problems.

Where have all the workers gone?

Over the past 15 years, utility companies have consolidated through mergers and acquisitions (M&A) to establish economies of scale that keep rates low. Between 1995 and 2012, the number of investor-owned utilities shrank by nearly 50 percent (see Figure 2).

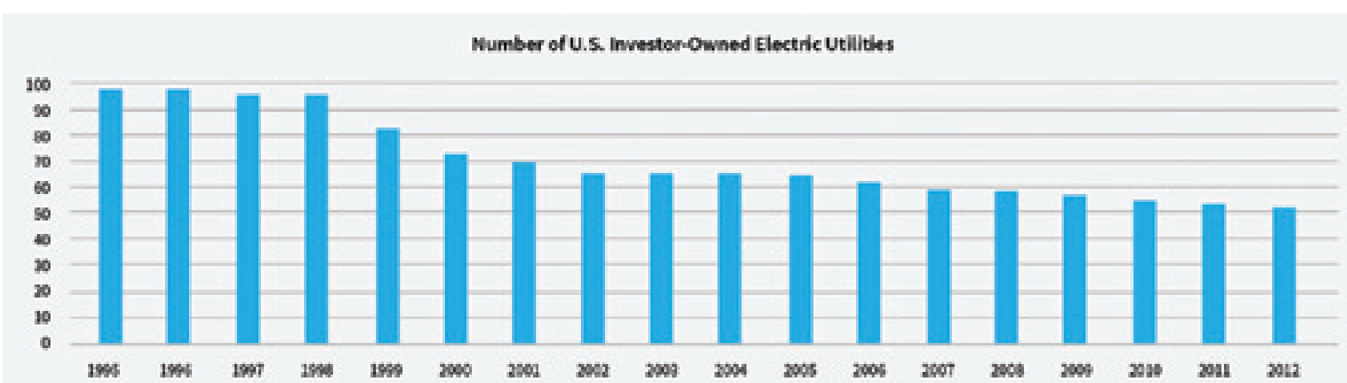


Figure 2: **Source: Public Utilities Fortnightly**

The consolidation of the utility landscape has unintended consequences; M&A's result in a serious shortage of skilled labor needed to respond effectively to outages and turn the lights back on.

In this highly regulated sector, agency approval is necessary for any M&A, and that approval consistently has been contingent upon the merging companies meeting cost-reduction targets. For example, when National Grid acquired Niagara Mohawk in 2000, New York State mandated nearly $200 million in cost reductions. In part, the merger achieved those savings through workforce reduction, including buy-outs and attrition.[2]

The Long Road to Improved Utility Storm Planning Begins Here

The Massachusetts Department of Public Utilities, in its approval of the 2012 Northeast Utilities/NSTAR merger, which is projected to save $784 million over 10 years, explained the rationale of workforce reduction to achieve those savings: 'The nature of merger savings, primarily staff reductions, are well within management's ability to estimate now and control later, so it is reasonable to conclude that these savings, at least, can be achieved.'[3]

But restoring power to customers as fast as possible depends almost entirely upon electric line workers going out in a truck, riding a bucket up to the top of poles, and fixing the poles and wires knocked down by wind, snow, ice, and falling branches. A 2011 survey conducted by the Center for Energy Workforce Development found a potential 32 percent reduction via retirement and attrition of electrical line workers from 2010 to 2015. As the total number of line workers has fallen, the average age has risen. A 2006 U.S. Department of Energy report found that in some organizations, half the line workers would be eligible to retire within the next five to 10 years.

Filling those positions won't be easy. The Bureau of Labor Statistics estimates that job growth for line workers – employment the agency describes as physically demanding with irregular hours – will be slower than average through 2022. Becoming a qualified electrical line worker requires between four and seven years of training.

A smaller, older workforce laboring in a hazardous, demanding occupation is likely to be less productive, exacerbating the problem of restoring power expeditiously. Yet post-Sandy studies largely have ignored the growing shortage of skilled, trained, able line workers and supervisors. Regulators are loath to authorize utilities to spend money to staff up and train; the primary concern is to keep rates as low as possible.

The difficulties surrounding mutual aid

Almost all post-Sandy reports stress the need for improvements to the mutual aid process – agreements to send utility company workers across municipalities and state lines when needed to address a crisis. Indeed, representatives from 36 utilities have worked diligently to create the National Response Event framework. But the resulting plan has yet to demonstrate its effectiveness. However admirable the concept of mutual aid may be, its workability is limited by several practical, real-world factors.

In order to expedite restoration, utilities must use contractors and other utility mutual aid crews as soon as the companies are 'free from significant threat.'[4] In the case of a hurricane, utilities can turn to these mutual aid and outside contractor resources up to a week or more in advance. Since mutual aid resources often cannot be made available early, these resources cannot be relied upon at the beginning of a restoration when needed most. Consequently, it can take up to three or four days to determine whether a utility can afford to release its employees, by which time reasonable recovery targets already will have been missed.

Although utilities face a financial risk if they call upon these resources early (if they turn out not to be needed), the risk is outweighed by the even greater costs, reputational damage and customer losses of not having crews at the ready.

In addition, utilities operating in multiple states ordinarily cannot (again by rule) send workers across state lines – even to its own locations - without the approval of state officials and often only after all the home state customers have been restored. The EEI National Response Event framework provides a leadership structure to manage a 'more efficient resource allocation.'[5] However, the revised mutual aid process – while enhanced – remains voluntary and likely will be too slow or late in providing assistance in the early hours of an event when needed most. The reports following Sandy almost unanimously missed these impediments to mutual aid.

Getting Real about the Practical Solutions in the Next Storm

To change public perception of electric utilities and restore investor confidence, companies must work to lower the peak and shorten the tail of outages caused by severe weather over the short term. Key elements include identifying which organizations are doing well at restoring power and developing better, consistent metrics across the industry.

Right now, states are increasingly proactive. In January 2014, New York State, for example, announced a competition to pilot 10 microgrids (independent community-based electrical distribution systems) for areas with approximately 40,000 residents. New York is proposing to spend more than $1.3 billion to fund electric grid resiliency. But attacking storm-caused power outages by introducing new systems or improving the infrastructure is expensive and will take years to implement.

It's the trees… and everyone knows it!

A faster, more diligent tree-trimming program to remove branches that bring down power lines is a practical near-term solution. A 2012 Connecticut State Vegetation Management Task Force report said that falling branches caused nine out of 10 power outages in the Connecticut Light & Power (CL&P) service area. In 2012, CL&P (a Northeast Utilities company) announced plans, after working with local arborists and receiving homeowner consent, to extend its annual trimming program from 3,200 to 4,800 miles. Connecticut has set up a special task force that calls for more state-supported funding at the local level to manage the state's roadside forests. Connecticut also encouraged municipalities to develop easily understood and centralized tree-pruning guidelines in order to cut through the red tape associated with trees on public roads that dictates (and frustrates) utility tree-trimming activities.

All states should work to smooth the path for utilities, allowing them to trim trees without having to get approval from every individual municipality and every town arborist before touching any tree in any given jurisdiction

Staffing levels and the use of contractors

The workforce battle is the one that electric utilities must fight now. Without skilled, ready workers to deploy, customers will be left in the dark for an unacceptably long time. Utilities must collaborate with regulators and governing authorities to free up the money necessary to rebuild workforces and training programs. At the same time, electric companies must be proactive in replacing retiring line workers.

To ensure that utilities have properly equipped, trained people who can be sent to the right places in a timely fashion, these companies should conduct diligent surveys of their service areas to make sure the appropriate resources are available in the most vulnerable areas. Electric companies also should develop strong, integrated, contractual relationships with accredited, reliable third-party contractors that can support remediation efforts once the lights have gone out.

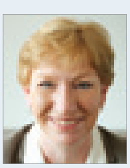
A Matter of Survival

The social cost of power outages is sizable in terms of human suffering. The economic cost in lost productivity – the value of lost load (VOLL) – for utility customers also is significant. VOLL directly relates to a customer's willingness to pay for reliable electric service. But VOLL – which depends on the type of customer affected, regional economic conditions, demographics and the duration of an outage – is difficult to measure. However, a 2013 Congressional Research Service study estimated the annual inflation-adjusted cost of weather-related outages to be between $25 billion and $70 billion. That toll will only increase as our economy becomes ever more reliant on the provision of uninterrupted, high-quality energy.

Public anger at utilities cannot be wished away or addressed by public relations campaigns. Negative sentiment inevitably will encourage the development of alternative energy distribution systems such as microgrids that lower demand for utility services and result in lost revenues to the companies. In a vicious cycle, these lost revenues will further hamper the utilities' ability to refresh and harden the infrastructure; to invest in new, cost-reducing technologies; and to rebuild a critical workforce.

Conducting 'business as usual' or planning for the future without dealing with the challenges of the present is a real threat to U.S. utilities. The likelihood of that threat is increasing and requires both short-term and long-term action.

ABOUT THE AUTHORS



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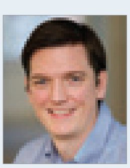

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Guest Editorial 2

How Utilities Leverage Data Analytics to Improve Efficiency and Enhance Operations

By Brian Crow, PE

For most electric utilities, outage management is a top priority and concern. Take, for example, an electric utility located in the middle of the United States' infamous 'Tornado Alley.' After a series of devastating storms and tornados hit, the utility experiences serious damage to its transmission and distribution systems. However, by combining meter data with its outage management system, the utility was able to complete all repairs to its transmission and distribution systems within a month. In addition to repairing its transmission and distribution systems in record time, this type of system efficiency helped the utility enhance its customer service as well as prevent the potential for significant revenue loss.

Through proper data management and the use of data analytics, utilities can maximize the value of all the data that their sensors are providing them to draw insights, identify current or potential issues, and enhance operations.

There is no denying that we live in an age of information. What really matters, however, is what we do with this information. After all, the information on its own is just that – data. Utilities are inundated with data. As utilities adopt communications systems to improve their operations, these networks are delivering a growing volume of data from both the utility's infrastructure as well as external sources such as news and weather aggregators. As a result, utilities are struggling to manage and determine how to best use this surge of information. However, through the use of data analytics, utilities can now better manage this information and, ultimately, improve system efficiency.

There are three steps to optimizing the value of data analytics:

1. Collect the data
2. Analyze the information
3. Convert data into actionable insights

1. Collect the Data

Communication networks provide data about power usage, the utility's infrastructure and even outages. While this information is useful, utilities are now asking:

- What else can this information tell me?
- Is there an opportunity to use this information to improve system operations?

It benefits utilities to think about the other sources of data they could be tapping into for a more comprehensive view of their system and operations.

Another key benefit is that data collection improves coordination, collapsing the walls between different utility departments. While areas such as customer service may have had limited interaction with operations, for instance, data collection and analysis enable every department to see the big picture. The actions of one department often affect the entire utility and data analysis helps to showcase this. Through the use of data collection and data analysis, every department is able to work together to improve operations for the utility as a whole as well as benefit its customers.

Utilities and their customers are craving basic data and visualization such as charts, graphs and online dashboards. However, with data analytics solutions, utilities can quench this thirst and realize even greater value hidden within this information. If one department in a utility begins to implement data analytics, other departments will see the results, embrace it and the walls will come down.

However, while sensors on the communication network provide utilities with this data, collecting the information is just the first step.

2. Analyze the Data

As the example above revealed, sharing data across departments within a utility can often address problems such as customer-related issues. While this type of data analysis is certainly useful to utilities, the real challenge lies in transforming this data into information that will benefit the utility, its customers and improve operational efficiency.

Utilities have two main options for how to analyze this data: they can either build a system in house or they can choose to source an outside data analytics vendor. There are certainly challenges and benefits with both options. When building a system internally, utilities have more control. More specifically, they have the complete ability to customize their data analytics system and do not have to determine the right vendor to partner with. On the other hand, this also poses certain challenges and obstacles, particularly for smaller utilities. For instance, a system might require buy-in across several departments within the organization as well as require numerous resources to maintain it. For smaller utilities, they might not have access to these resources, making this option less advantageous.

The second option is to work with an outside vendor. Data analytics is an evolving space; if a utility sources an outside vendor to supply and manage its data analytics system, software updates, for example, are seamless to implement. In addition, for many utilities and especially IOUs, they might have internal constraints to deal with. Very often, they cannot take the risks required to advance their own data analytics campaigns. Smaller utilities oftentimes do not have the resources necessary to build a system in-house so working with an outside vendor might be the best option in those situations.

Regardless of which option you choose, implementing data analytics allows utilities to continuously review, monitor and verify data. And the benefits are limitless. One major benefit is that utilities no longer need to continuously monitor data on their own. Data intelligence provides a series of routines to assure multiple checks and balances of the data. By using routines that verify data, utilities can expect to save both time and money.

This data intelligence also allows the utility to assign the appropriate action to automatically adjust any perceived discrepancies in the data. Utilities can pre-select responses and organizational tactics for different types of incoming information. This continuous and instant monitoring allows utilities to run more efficiently and better serve their customers. Data analytics can also immediately alert customers to certain occurrences or issues, helping improve response rates and enhance customer service. Customers can receive automated notifications and alerts at the very moment something is wrong. This type of automated notification can cut response rates and increase operational efficiencies, enhancing customer services as a result.
In this age of technology, this rapid response is not only wanted but it is expected by customers.

Given the ever-changing nature of the electric industry, data analytics provides flexibility through vast customization options to address the varying skill sets and needs within a particular utility. In addition, such agility allows for enhanced integration of complex networks. Through the use of data intelligence, utilities can solve nearly any data-related issue while also incorporating a sophisticated platform that can address more complex needs.

For utilities, another significant benefit of data analytics is revenue forecasting. With the ability to continuously bring in meter data every fifteen minutes, instead of just once a month or more, utilities can track their earnings in real time. Additional benefits include pulling customer information, better managing the business, segmenting sales data via customer classes, and estimating budgets to conserve costs and improve operations.

3. Convert the data into actionable insights

With the massive influx of data that utilities receive on a daily basis, a key part of data management is being able to sort through all of this information and pull in actionable insights. To truly benefit from such a large amount of data, utilities need to determine what data is required to best improve operations, reduce costs and enhance customer service.

One key example is a utility with a failed transformer. Prior to data analytics, the utility would automatically install a larger transformer, assuming that the previous transformer failed due to its load. However, by using data analytics, the utility was able to determine that the transformer did not fail due to demand and was, in fact, too large for its system. Based on this data, the utility was able to replace the transformer with one at the appropriate size. Many utilities are even able to downsize their transformers on a broad scale. Data analytics can also enhance customer service for utilities. With data analytics, utilities can prevent customers from losing power during an unscheduled outage by predicting potential transformer failure. Transformers never fail at the time most beneficial to the utility to replace and often fail at the most expensive time of day and at the largest impact to the customer. Ultimately, the ability to gather and analyze this type of information can help utilities enhance their customer service, preventing customers from losing power by predicting transformer failure.

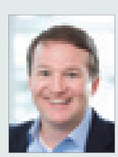
Reap the Benefits of Data

The combination of data management and analytics enables utilities to take a system-wide view of their operations, allowing them to run more efficiently and lower costs. It also allows utilities to better serve their customers by turning data into actual intelligence. With the right data analytics solution in place, utilities can manage their data and, most importantly, use this information to improve their utility and benefit the customer experience.

In addition to providing benefits to both the utility and its customers, data analytics provides environmental and societal benefits. Through the use of data analytics, utilities can not only monitor customer usage but also educate customers on their consumption. More specifically, data analytics can provide customers with regular alerts on their energy usage. By bettering informing customers about their energy consumption, they will become more aware of the amount of energy resources they use. This enables customers to be more knowledgeable about their consumption and can even promote customers to self-initiate conservation.

Ultimately, if utilities want to truly maximize the benefit of the data they are receiving from their sensors, data analytics is key. By collecting the data, analyzing its information and pulling actionable insights, utilities can gather information from grids, infrastructure and external sources to improve operations, reduce cost and inefficiencies and enhance customer service. Every utility has unique challenges, but the solution lies in data for many.

ABOUT THE AUTHOR



Brian is an 18-year utility industry veteran whose entire career has been focused on finding solutions to the challenges utilities face across their enterprise. Prior to joining Verdeeco, a Sensus company, Brian worked for the SAS National Utility Practice where he focused on providing utilities with analytic products such as load forecasting and energy trading risk measurement. Brian is a licensed Professional Engineer in the State of Georgia and received his BSAE degree from the University of Georgia.

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